CANADIAN HUNTER 2000 ANNUAL REPORT

the relentless pursuit of value

AR.'00

Canadian Hunter is a natural gas and crude oil exploration and production company based in western Canada. Our shares trade on the Toronto Stock Exchange, under the symbol HTR.

Annual Meeting

Shareholders are invited to attend Canadian Hunter's Annual Meeting scheduled for May 16, 2001, at 2:00 p.m. in the Imperial Ballroom at the Hyatt Regency Hotel, 700 Centre Street South, Calgary, Alberta.

Abbreviations

mcf	thousand cubic feet
mmcf	million cubic feet
bcf	billion cubic feet
bbl(s)	barrel(s)
mbbl(s)	thousand barrel(s)
mmbbl(s)	million barrel(s)
boe	barrel of oil equivalent
mboe	thousand boe
mmboe	million boe
mmbtu	million British Thermal Units
/d	per day
GJ	gigajoule

Note: Gas converted to oil equivalent at 6 mcf = 1 boe unless otherwise stated.

2000 was a year of outstanding results for Canadian Hunter.

- We increased production 20 percent to 81,104 barrels of oil equivalent (boe) per day
- We increased proven reserves 23 percent to 212 million boe
- We increased cash flow from operations 143 percent to $593 million
- We increased net income 203 percent to $208 million
- Our return on equity was 40 percent

We created value for our shareholders.

2000 Financial and Operating Highlights

YEAR ENDED DECEMBER 31 (UNAUDITED)

	2000	1999	% CHANGE
Financial ($ MILLIONS)			
Gross production revenue	909	401	127
Funds from operations	593	244	143
Net income	208	69	203
Return on equity (%)	40	18	122
Return on capital employed (%)	35	12	191
Capital expenditures			
Exploration and development	357	241	48
Acquisitions	148	48	206
Dispositions	(31)	(10)	196
Long-term debt at year end	235	160	46
Per Share Information			
Funds from operations per share			
Basic	9.96	4.10	143
Fully diluted	9.56	3.97	141
Net income per share			
Basic	3.49	1.15	203
Fully diluted	3.37	1.12	201
Common shares outstanding			
[AT DECEMBER 31] (THOUSANDS)			
Basic	59,577	59,564	–
Fully diluted	62,245	61,880	1
Operating			
Production			
Natural gas (mmcf/d)	430	357	20
Crude oil (bbls/d)	1,376	1,965	(30)
Natural gas liquids (bbls/d)	8,068	6,216	30
Total (boe/d)	81,104	67,721	20
Prices			
Natural gas ($/mcf)	4.96	2.60	91
Crude oil ($/bbl)	34.64	26.01	33
Natural gas liquids ($/bbl)	36.46	18.90	93
Proven reserves			
Natural gas (bcf)	1,137	915	24
Crude oil and liquids (mmbbls)	22	20	9
Barrels of oil equivalent (mmboe)	212	173	23
Canadian finding and development costs ($/boe)	8.82	4.70	88
All in replacement costs ($/boe)	6.91	4.95	40
Net undeveloped land holdings (THOUSAND ACRES)	1,879	1,453	29
Netback ($/boe)			
Product revenue	30.49	16.20	88
Royalties	(6.72)	(2.98)	126
Operating expense	(1.88)	(1.96)	(4)
Operating netback ($/boe)	21.89	11.26	94

Gross Revenue
($MILLIONS)

Cash Flow
($/FULLY DILUTED SHARE)

Net Income
($/FULLY DILUTED SHARE)

Return on Average Shareholders' Equity
(%)

Exploration and Development Capital Expenditures
($MILLIONS)

Drilling Activity
(TOTAL WELLS - GROSS)

Proven Reserves
(mmboe)

Production
(boe/d)

Left to right:

Murray Lueke
Senior Vice President, Engineering and
President, Canadian Hunter Argentina, S.A.

Steve Soules
Senior Vice President, Chief Financial Officer
and Corporate Secretary

Steve Savidant
President and Chief Executive Officer

Mike Downey
Senior Vice President and Chief Operating Officer

Chief Executive's Message to Our Shareholders

2000 was an extraordinary year for Canadian Hunter. Following up on success – particularly the type of success Hunter achieved in 1999 – is always a major challenge. I am pleased to report that we have met this challenge and pushed beyond.

We increased earnings 203 percent to $208 million and $3.37 per fully diluted share. Our cash flow increased 143 percent to $593 million or $9.56 per fully diluted share. We achieved a 40 percent return on equity – enviable results, even in a year of remarkable commodity prices.

However, at Canadian Hunter we understand our goal is to deliver returns superior to the industry average through all phases of the energy commodity price cycle. We will do this by finding, developing and producing new reserves of primarily natural gas on a value-adding basis. This is the same fundamental strategy that Canadian Hunter has employed over its 28-year history. We know it well. We execute it very well. So while our financial performance throughout the year was indeed extraordinary, of primary importance are our operating results. We believe we have a compelling story to tell here too.

In 2000, we increased production to 81,104 boe per day, a 20 percent increase over the 67,721 boe per day we produced in 1999. We drilled 332 wells in 2000; over 70 percent of the wells were exploration oriented. Our overall success rate was 85 percent.

Our focus on a low cost base continues. Finding and development costs of $8.82 per boe in Canada were up significantly from 1999, mostly due to inflationary increases in costs resulting from high industry activity and our aggressive land purchase program. We believe, however, our finding and development costs are still below expected industry averages. Another important element is our operating costs. Operating costs per unit of production were reduced by 6 percent in Canada in 2000 from a level in 1999 that was already among the lowest in the industry.

We are currently operating in a high price, high cost environment. As demand for natural gas escalates, so does our search for new supplies. However, the intensity of that search results in even more competition for land, equipment and people resources. Because of this, there are significant challenges as well as great opportunities for Canadian Hunter in 2001. Here are some of the ways we have prepared to meet those challenges and continue to deliver value for our investors.

READY FOR 2001 AND BEYOND

Our strategy for growth is simple. We will continue to grow Canadian Hunter by exploring for natural gas and liquids on a value basis. We pursue this strategy not because it is easy, but because it is what we do best.

Later in this annual report our Chairman heralds a new age of natural gas exploration in western Canada. We are excited by this prospect and believe Canadian Hunter is superbly positioned to capitalize on these new exploration opportunities.

Canadian Hunter was one of the first gas focused exploration and production companies in Canada. Our discovery of the Deep Basin in 1976 – a giant among North American gas fields – not only helped to build our company, it also helped to establish Canada's natural gas industry. While our corporate structure has changed over the years, culminating in our introduction as a public company in 1998, this heritage still shapes Canadian Hunter today.

From our discoveries in the Deep Basin 25 years ago, to our recent successes at Kaybob and Lethbridge, we have proven our exploration skills can transform complex geology into a productive and valuable resource. As we push out the boundaries of our operating fairway to increase reserves and production, we are focussed on continuing to deliver a return on capital that is one of the highest in our industry.

We need undeveloped land to expand Canadian Hunter's exploration activities. In 2000, we strengthened our land position in western Canada with the acquisition of approximately 400,000 acres. This brought our net undeveloped tracts of land to 1.8 million acres in the gas prone fairway that Hunter has been playing successfully for the past 28 years. It is a substantial platform that will allow Canadian Hunter to continue exploring for and producing natural gas and liquids well into the future.

TAPPING OPPORTUNITY TO DELIVER VALUE

We anticipate increased spending again in 2001, which will allow us to continue transforming the opportunity represented by our undeveloped land into value for our shareholders. We plan to allocate approximately one third of our capital spending to exploratory drilling activity, Canadian Hunter's engine of growth.

The cost of land, people and other resources has increased for all companies in the Canadian energy sector. We continue to achieve finding and development costs at levels below the industry average, however the current inflationary environment will increase industry costs in 2001.

A real benefit of increased prices however, is that they increase our range of exploration targets. Stronger prices mean we can profitably find and produce tighter, deeper and higher-cost gas. In the current strong price environment, we believe it is prudent to widen the range of targets we pursue, and tap solid but higher cost opportunities.

In 2000, with our $134 million investment in the Sierra Chata gas field in the Neuquén Basin in Argentina, we diversified outside the Western Canadian Sedimentary Basin. We did this because there are good opportunities abroad to lever the skills we have developed at home and create value for our shareholders. The Sierra Chata gas field resembles the geology of the Western Canadian Sedimentary Basin, and Argentina's natural gas industry looks much like Canada's did in the 1970s – with room for demand growth, a large, relatively untapped producing basin and plenty of upside remaining. By investing in Argentina, we believe we are diversifying and strengthening Canadian Hunter's portfolio of opportunities.

In 2001 we will continue to evaluate opportunities to add to our international asset base by investing in geological regions like the Neuquén Basin, in countries like Argentina that offer superior rates of return in a relatively moderate-risk environment.

WORKING TOGETHER – PURSUING VALUE

Once again, the skills, experience, discipline and creativity of the people of Canadian Hunter have produced outstanding results for our shareholders. We will never lose our enthusiasm for exploration. However, an understanding of the earth is not sufficient, by itself, to deliver superior results. It also takes thorough commercial analysis, marketing acumen, cost discipline and an unrelenting focus on value creation. We evaluate every prospect, every project, every opportunity from that most important value perspective. We would like to thank the employees of Canadian Hunter who have once again proven their determination to deliver on this simple but powerful formula.

The year 2000 also saw the end of our formal relationship with the Brascan group. That relationship, initially through Noranda and then directly with Brascan, extended back to the beginning of Canadian Hunter in 1973. We would like to acknowledge and express our appreciation to David Kerr and Jack Cockwell for their exceptional support and counsel over many years. We also want to thank Brian Kenning for his contribution to Canadian Hunter as it became a public company at the end of 1998. These three representatives of Brascan retired from the Board of Directors at the time of the secondary offering of Brascan's 40 percent shareholding last April. We have also had the good fortune to welcome Larry Bell and Cedric Ritchie as new directors to the Board.

And finally, but no less importantly, we thank you our shareholders for your support of Canadian Hunter throughout 2000 and now in 2001. Our relentless pursuit of value continues together.

Stephen J. Savidant
President and Chief Executive Officer
March 5, 2001

Q :

Steve Savidant

Almost every company in the energy sector had a great 2000. What differentiates your performance from that of other exploration and production companies?

When you strip away the price effect that sent earnings and cash flow soaring throughout the industry, Canadian Hunter added shareholder value by doing what it does best – adding substantial volumes of new reserves and bringing on production at low costs.

Canadian Hunter is one of a few companies of this size with such a substantial emphasis on, and track record for, exploration. Of the 332 wells we drilled in 2000, 72 percent were exploration wells. Canadian Hunter drilled the second highest number of exploration wells of any company in Alberta and British Columbia in 2000, and we had more gas discoveries than any other explorer in western Canada. We are proud of this achievement and very satisfied with the results.

In 2000, Canadian Hunter increased production by 16 percent and reserves by 6 percent in Canada, entirely through exploration and development activities – through the "drill bit". We reduced operating costs per unit of production by 6 percent in Canada. Our exploration success rate was 83 percent. While our finding and development costs rose substantially, we believe they will continue to be in the best quartile of industry once all reporting is completed. None of these performance measures are influenced by commodity prices.

Beyond 2000, we believe Hunter will continue to differentiate itself by its ability to explore in the higher cost, higher risk, higher reward and more technically complex areas of the Western Canadian Sedimentary Basin. And it is to these areas that the industry is turning to grow gas production.

Q :

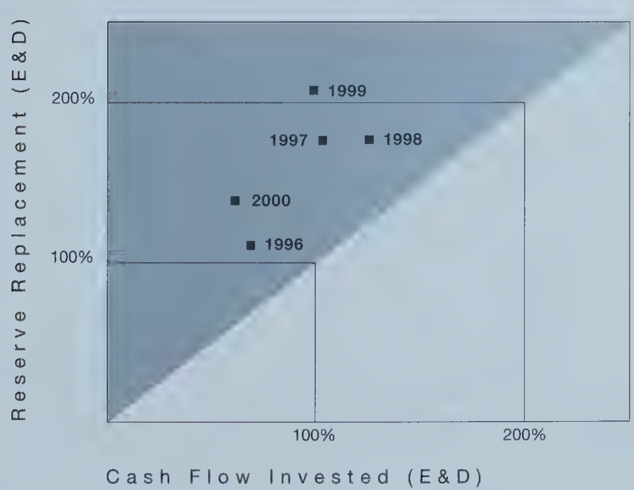
Murray Lueke

Why does Canad[illegible] reserve replace[illegible] as important perfor[illegible] about reserve life index?

Canadian Hunter's proven reserve life index (RLI) rose to 7.1 years in 2000, mainly due to the acquisition of long-life reserves in Argentina. In Canada, our proven RLI is 6.3 years. We believe it is also important to look at the makeup of those reserves, however. Eighty-three percent of Hunter's reserves in Canada are proven developed. On a proven developed basis, Canadian Hunter's RLI is close to the industry average, and it has been in this range for the past decade.

However, the other important factor to consider is Hunter's ability to replace reserves on an ongoing basis through the drillbit. The capital efficiency ratio is the relationship between the percentage of annual production replaced during the year and the percentage of cash flow invested to accomplish this. For example, in 1999 we replaced 207 percent of our production by spending 98 percent of our cash flow. This generates a capital efficiency ratio of 2.1. In 2000, we spent only 60 percent of our cash flow (cash flow was up due to higher prices and production), but we replaced 134 percent of production, generating a capital efficiency ratio of 2.2. We see this ability to replace production efficiently as strong evidence of our record of adding value for our shareholders.

Reserve Replacement & Capital Efficiency



Q :

With such [illegible] prices for natural [illegible] why are you investing in [illegible] prices are substantially [illegible]

In 1997, a combination of highly cyclic natural gas prices and the depressing effect of extraordinarily intense competition on our industry's fundamental rates of return through most of the 1990s, led Canadian Hunter to look at opportunities for global diversification that would enable us to project our competencies to other regions with the promise of superior returns to those traditionally available in western Canada. The southern cone of Latin America, and initially Argentina, drew our interest for a number of reasons:

- Similar geology to western Canada: Our technical people saw analogous fields to those we explore and develop in Canada. We believe we can successfully employ our technical skills in Argentina and elsewhere in the southern cone.
- Relatively stable political and fiscal regimes: Argentina, Brazil, Chile and Bolivia all met our criteria in this regard.
- Attractive rates of return: Our early analysis, subsequently supported by our first 2 investments, made in 2000, points to very satisfactory rates of return – certainly superior to those achieved by the Canadian industry in the '90s, but not as strong as those being achieved currently in Canada – in its high phase of the North American commodity cycle. Canadian Hunter takes a long-term view with regard to its capital spending strategy and expects its investments in Argentina to perform well for the Corporation over the full cycle.

Prices make up only one element of the economic attractiveness of a region. Argentina boasts lower taxes and royalties when compared to Canadian regimes, as well as attractive finding and operating costs.

The energy requirements in the southern cone are growing dramatically and with that growth comes the prospect of significant real price increases for natural gas over the next few years.

Q :

Mike Downey

You have shown [illegible] duction and [illegible] you have been [illegible] you continue to [illegible]

Canadian Hunter's growth has historically come from, and will continue to come from, the broad fairway running from south central Alberta up to northeast British Columbia. This fairway encompasses our existing asset base but offers much more in terms of new exploration opportunities. Most of our current properties are not mature, and they still yield significant exploration successes and production growth year after year.

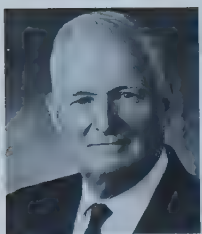
A perfect example of this is our Deep Basin property, which is profiled in this annual report. The Deep Basin has been producing for 25 years, after being discovered in 1976. Despite its long history, 65 percent of the wells we drilled in the Deep Basin last year were exploratory and the Deep Basin not only replaced its 25 percent decline rate, but increased production by 7 percent. The Deep Basin team achieved that by spending only 37 percent of their cash flow. They spun off over $200 million in excess cash flow for reinvestment elsewhere in Canadian Hunter.

Border is another long-time asset in which we continue to expand production. For the past 3 years the Border area has generated in excess of 20 percent per annum growth in production. Well over half of our 2001 production growth in this area will come from 5 step-out areas that have extended our reach well beyond the original unitized production base.

In addition to continuing exploration and development in our core areas, we are expanding into the Foothills west of our current asset base. The Foothills is a high risk/high cost game, but it also comes with high rewards. The Foothills has very complex geology and we believe it plays to Canadian Hunter's strength as a highly technical company.

Another area where we will continue to expand is in Argentina. The two acquisitions we made in 2000 have brought Argentine production to 6 percent of the total for Canadian Hunter. We continue to assess opportunities in Argentina and onshore Brazil, with the ultimate goal of having 20 percent of our production sourced outside of Canada by 2005.

Chairman's Message



This is the dawn of a new age of exploration in the Western Canadian Sedimentary Basin. Growing demand for energy across North America, in particular natural gas, has driven commodity prices to new heights. At the same time the basin is maturing. This means that while there's still plenty of natural gas left to find and produce, the easy gas is mostly gone. Now, more than ever, exploration companies are turning their attention to gas that's deeper and tighter; gas that's more difficult to find and more costly to produce.

No doubt, some view this new age of exploration with trepidation. At Canadian Hunter, we see it as an exciting opportunity. We believe that the future will belong to companies like ours; companies with the people, assets and expertise to understand and exploit the potential that lies deep within the earth.

This is why I believe that the 232 Hunters who constitute this fine company welcome the new age of exploration in the Western Canadian Sedimentary Basin.

James K. Gray
Chairman and Co-Founder, Canadian Hunter
March 5, 2001

NAME
NOM **Deep Basin**

NO. 2000

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Canadian Hunter's culture of value-focused exploration evolved from our early discoveries in the Deep Basin. With estimates of ultimate resource potential for the area exceeding 10 trillion cubic feet of natural gas, the Deep Basin is one of the largest natural gas basins in North America. Even today, after 25 years of intense exploration and production activity, the Deep Basin is still only moderately drilled.

The Deep Basin hol
vast reserves of natu
layered from depths
to 3,000 metres
For some, the comp
geology of the Deep
is too daunting, b
this resource rich, com
region that we honed
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Deep Basin

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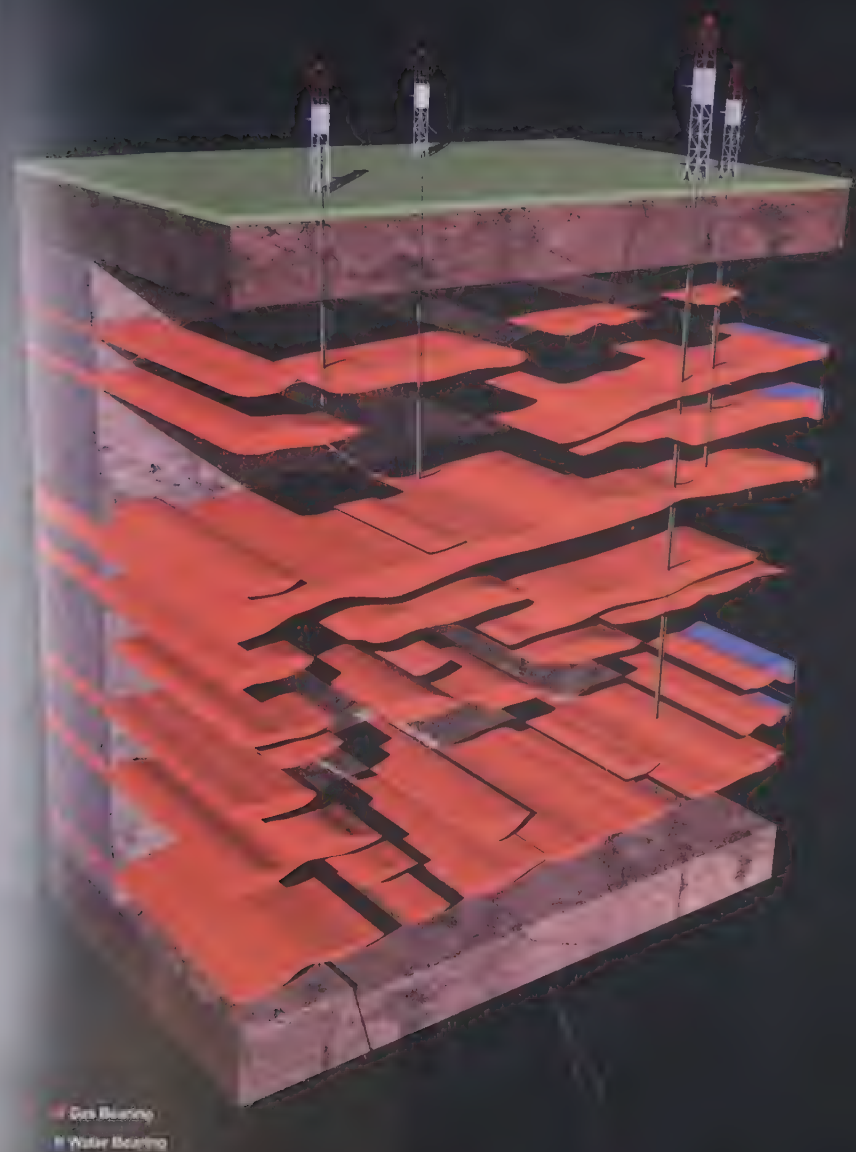
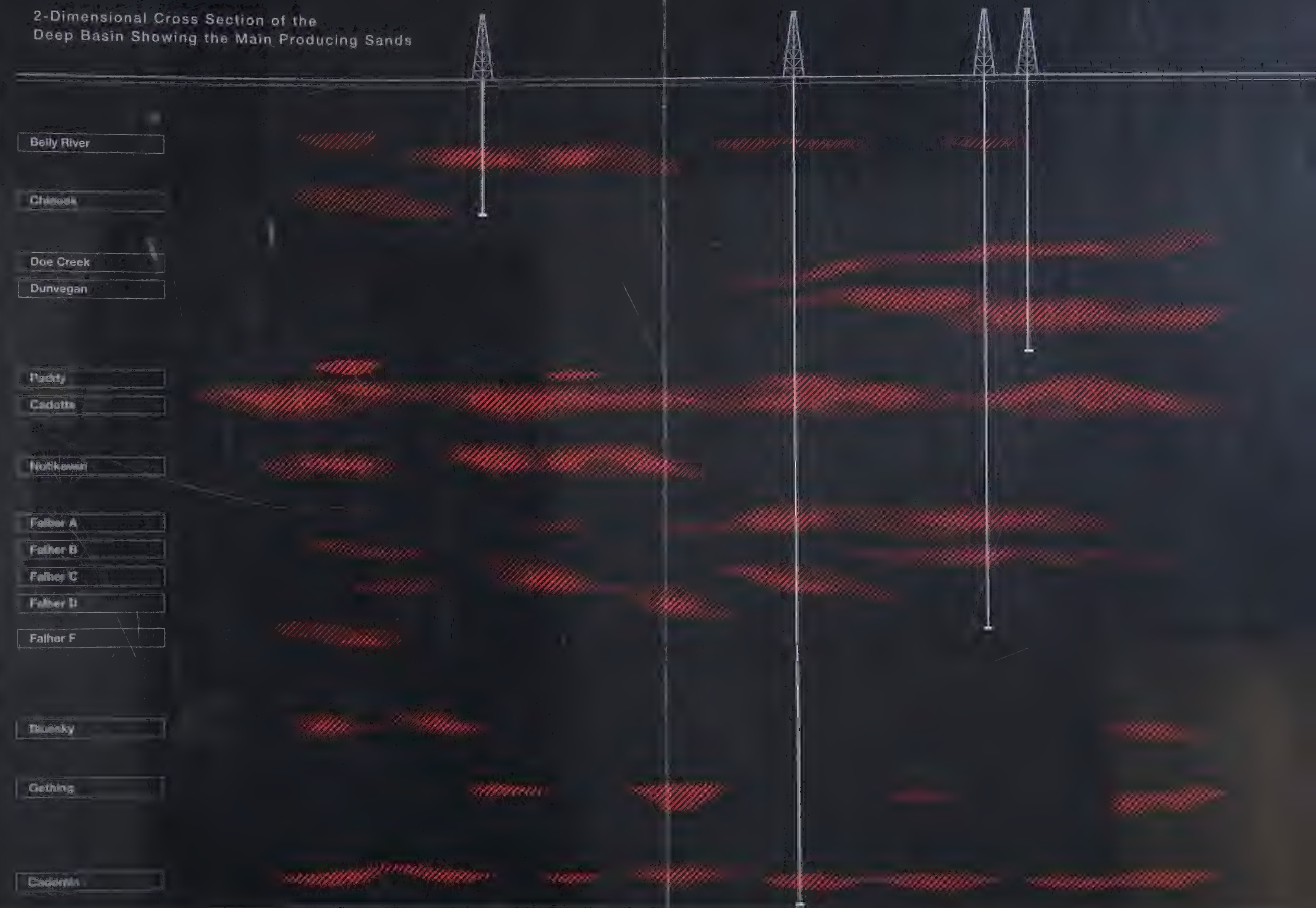
3-Dimensional View of the Deep Basin



Geology in the Deep Basin is very complex, and the presence of interbedded coals makes it difficult to use seismic to explore. However, because the Deep Basin produces gas from many different zones or horizons, drilling stacked targets reduces risk. Canadian Hunter's capital and operating costs in the Deep Basin are low, due both to our expertise in exploration and operations and the benefit of almost three decades spent learning the Basin's geological quirks.

2-Dimensional Cross Section of the Deep Basin Showing the Main Producing Sands



In 2001, we plan to exceed last year's capital spending of $140 million in the Deep Basin. In addition to the typical targets, we plan to take a larger number of wells deeper into some of the tight gas formations such as the Cadomin, and extend the scope of the Deep Basin plays west into the Foothills. Although the tighter sands have modest reserves and production per well, we will exploit opportunities for stacking multi-zones in an attempt to mitigate risk.

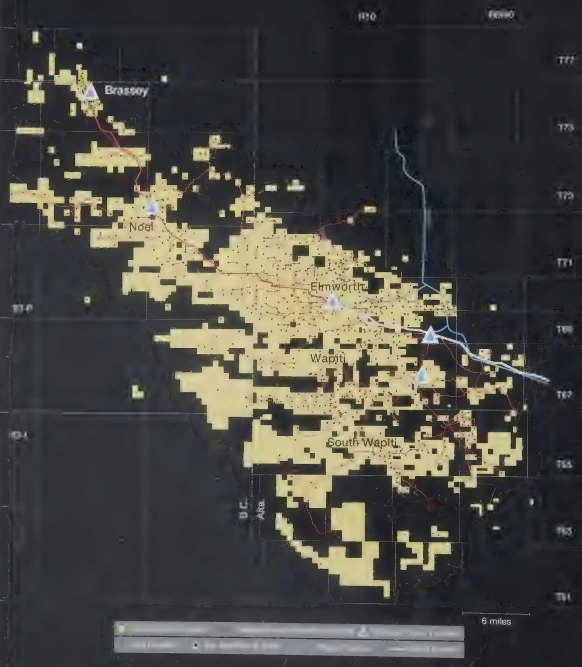
The Foothills, on the western edge of the Deep Basin, is a high risk/high potential natural gas play that is just beginning to be explored. Canadian Hunter acquired a significant amount of land on the Foothills trend in 2000, and we have begun drilling exploration wells in this highly complex area.

Deep Basin Statistics

	2000	[illegible]	[illegible]
Land position			
Total net acres	1,434	1,545	1,292
Net undeveloped acres	718	648	658
Well information			
Wells drilled	83/63	99/63	73/43
Exploration/development	65/35	64/36	46/54
Success rate	84/86	[illegible]	78/82
Average production			
Natural gas	242	[illegible]	200
Natural gas liquids	5,893	4,873	4,162
Crude oil	932	[illegible]	1,837
Total	47,121	44,209	39,369
Capital expenditures			
Exploration & development	140.4	[illegible]	[illegible]
Operating income	379.5	180.6	131.3
Reinvestment ratio	37	54	60
Netback			
Price	29.86	15.64	12.36
Royalties	(6.63)	(3.01)	(2.29)
Operating costs	(1.37)	(1.52)	(1.41)
Operating netback	21.86	11.11	9.16

In 2000, the Deep Basin contributed 64 percent of Canadian Hunter's cash flow, generating $239 million in excess operating income from an investment of $140 million for exploration and development activities. Production from the Deep Basin increased 7 percent during the year, despite decline rates of up to 25 percent in this area.

Deep Basin



The gas saturated Deep Basin covers an area of 13,000 square kilometres, stretching from north-central British Columbia into the foothills of Alberta. A total of 63 net wells were drilled in the area in 2000, 65 percent of these exploratory, and our success rate on these wells topped 86 per cent. Although the number of gross wells drilled in 2000 dropped from 1999, this was due to reduced partner activity; the number of Canadian Hunter operated wells stayed constant. Our partners appear to be more active this year, so we expect to drill approximately 100 gross (65-75 net) wells in 2001.

Our success in the Deep Basin has helped establish Canadian Hunter's strong commercial and technical foundation. The natural gas marketing team plays a vital role in converting the volumes of gas into bottom-line value.

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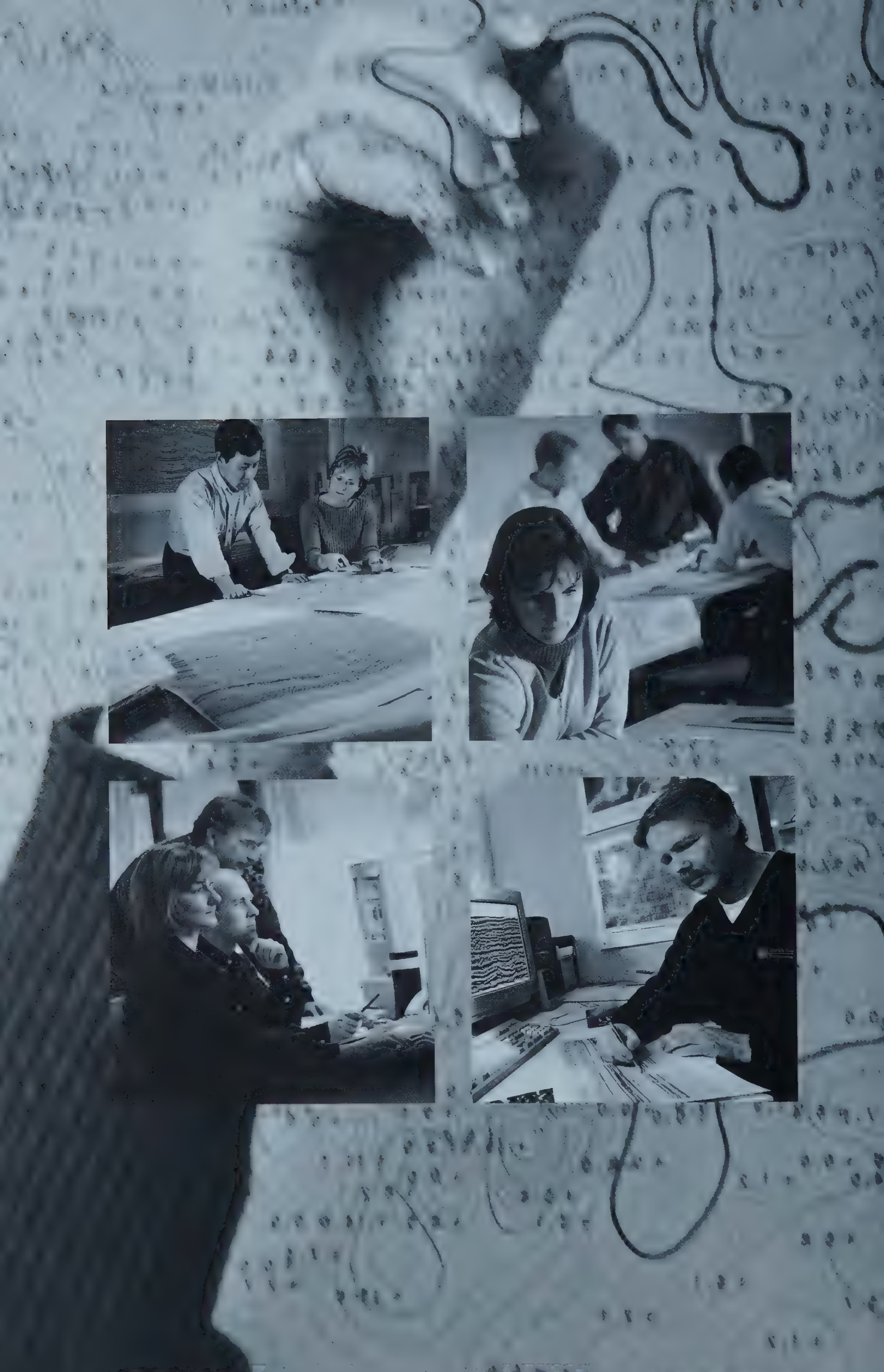
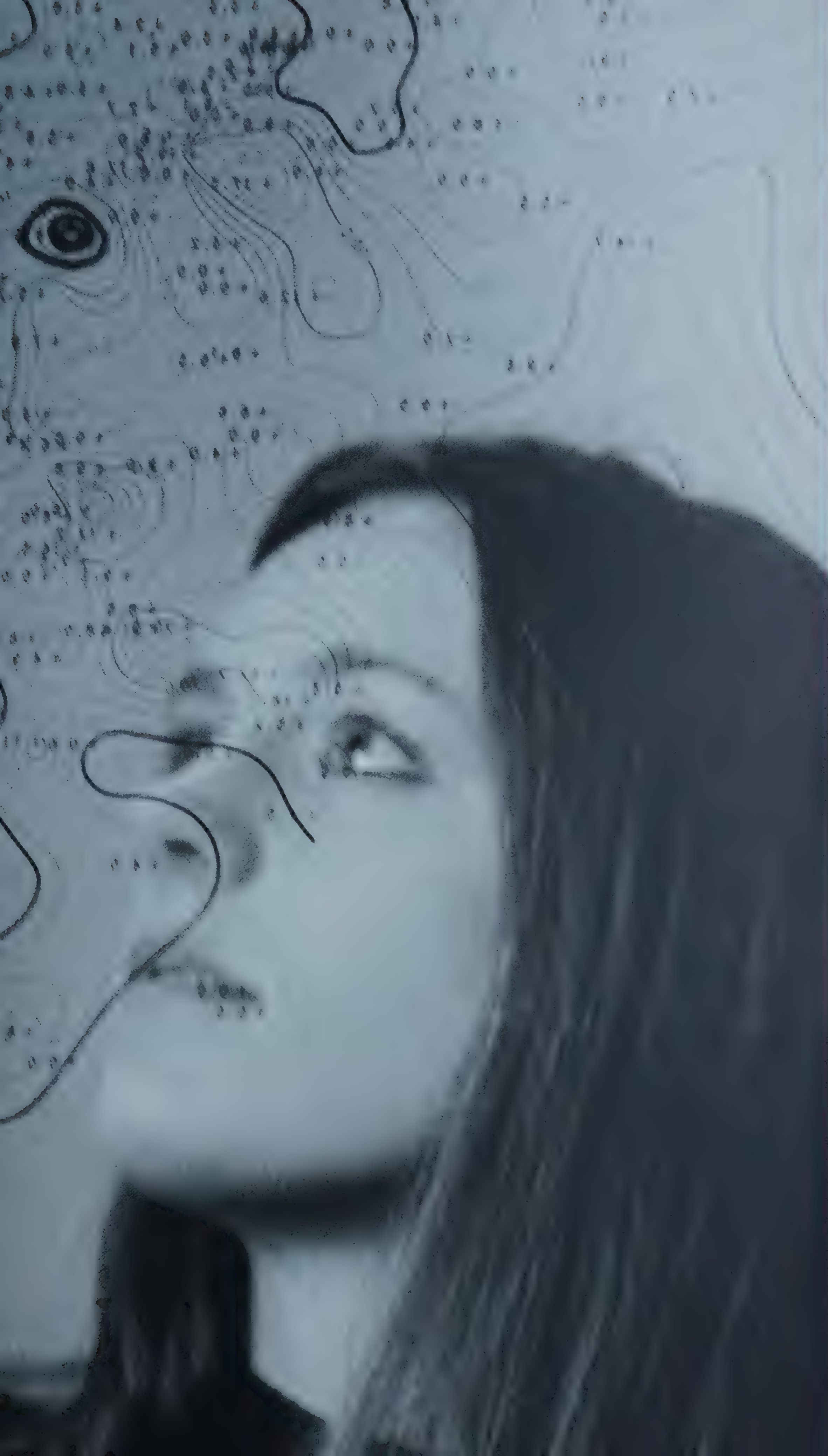
Deep Basin

the relentless pursuit of value

NO. 2000



Hunter's business unit teams integrate multi-disciplinary expertise to bring technical and commercial input to decision making. Earth scientists, marketers, engineers, land negotiators and economists all contribute to the development of strategies for exploiting each property.



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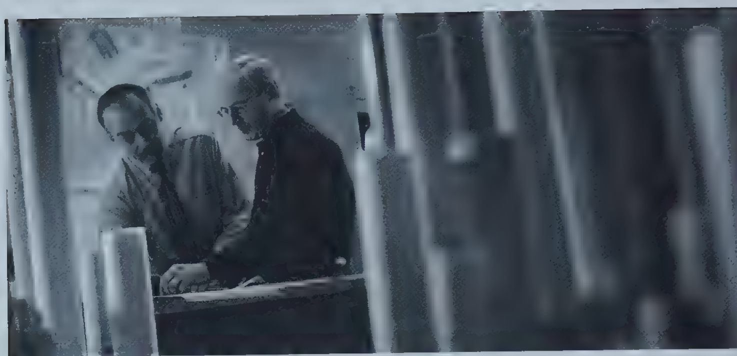

Our teams of earth scientists and business experts determine the economics of our drilling program. Their teamwork establishes when, where – even if – we drill, and ensures maximum value creation for our shareholders.

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From our di
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push out the
grow reserve
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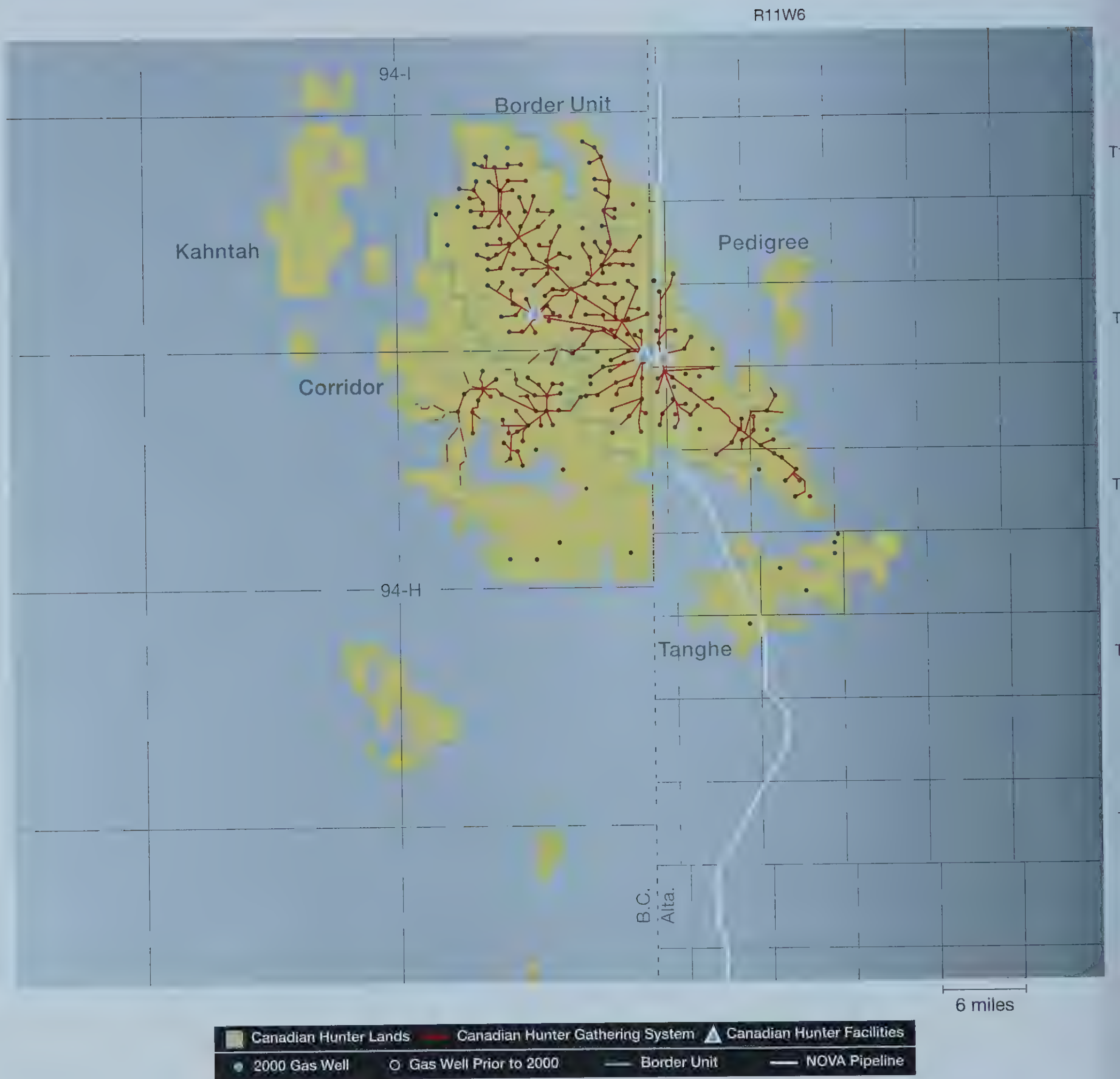
capital that is

Border/Corridor



Border/Corridor is a large, low-risk, winter-access area where we have a significant undeveloped land base. Our successful drilling program increased production here by [illegible] percent in 2000. A total of 46 net wells were drilled, with much of the production increase coming from the Corridor area, where Canadian Hunter has a very high working interest. We have an average working interest of 41 percent within the 2 Border Units and interests ranging from 40 to 100 percent outside the unit boundaries.

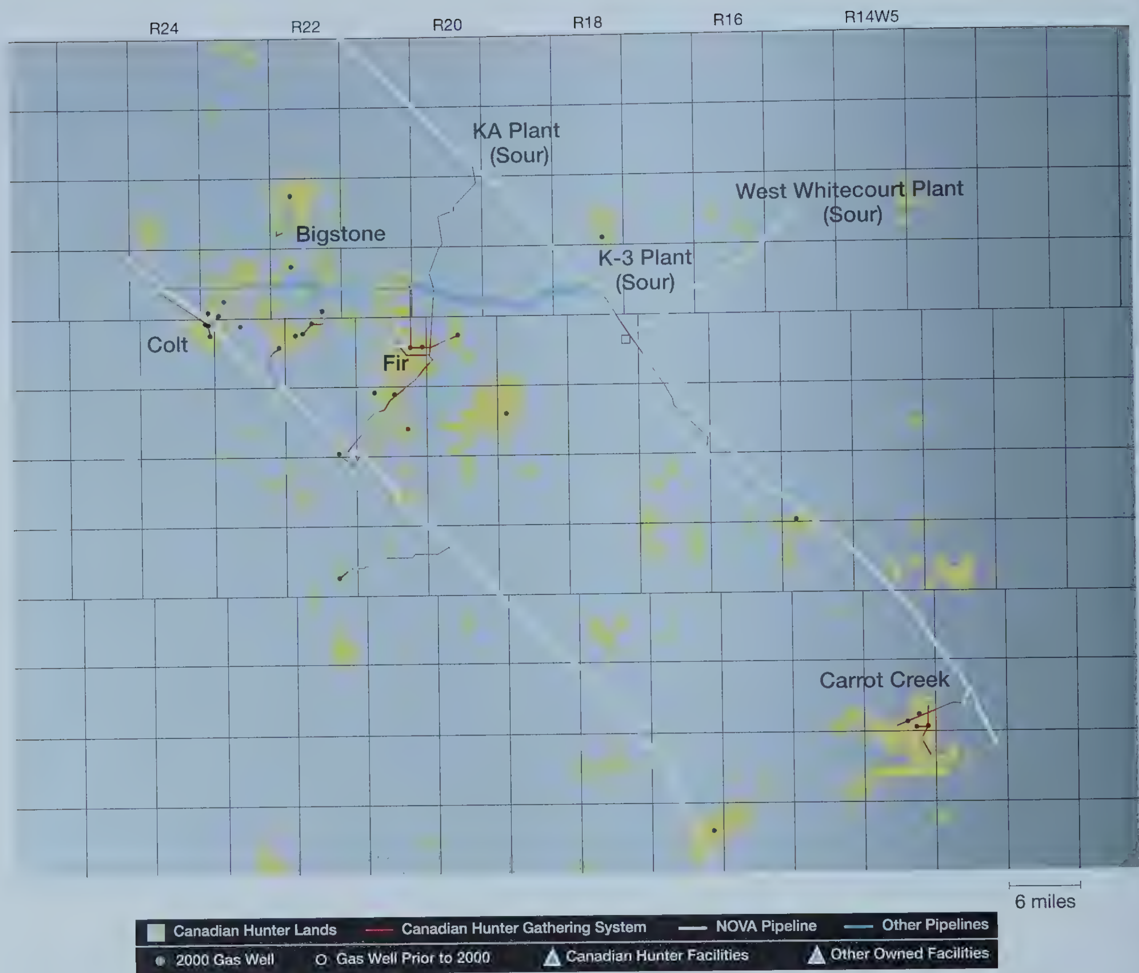
In 2000, we consolidated our land holdings in the Tanghe area and we now have roughly a 90 percent working interest there. In 2001, we plan to tie gas in from Tanghe and the Pedigree areas, where Canadian Hunter has a 75 percent working interest. We also had significant exploration success in the Kahntah area, where we have a 100 percent working interest.

In 2001, activity will be primarily focused in the Corridor area and on expanding our production and infrastructure base. This year's drilling program targets reserves in the Montney, Bluesky and Gething formations. Wells here average 800 metres in depth and cost approximately $320,000 to drill and complete. Reserves average 2 bcf per well with decline rates of about 15 percent. The area has an intense seismic focus, and we have increased our seismic inventory substantially in this northern area over the past 2 years.

Canadian Hunter plans to spend $60 million in the Border/Corridor area in 2001 with a total of 90 wells planned. We anticipate production will increase by an additional 20 percent in 2001, as a result of another successful winter drilling program and from the tie-in of wells drilled in 2000. To capture opportunities presented by the current commodity price environment, we will also exploit smaller targets with reserves averaging 1 bcf per well.

	2000	1999	1998
Land position			
Total net acres (000s)	**504**	403	250
Net undeveloped acres	**351**	274	164
Well information			
Wells drilled (GROSS/NET)	**63/48**	57/37	40/28
Exploration/development	**63/37**	40/60	43/57
Success rate (%) (GROSS/N	**92/92**	98/99	90/90
Average production			
Natural gas (mmcf/d)	**65**	52	42
Natural gas liquids (bbls/d)	**1,127**	819	685
Crude oil (bbls/d)	**–**	–	–
Total (boe/d)	**11,902**	9,408	7,677
Capital expenditures (exploration & development)	**37.9**	26.3	29.0
Operating income ($ MILLIONS	**112.4**	45.9	25.6
Reinvestment ratio (%)	**34**	57	113
Netback			
Price	**35.09**	18.36	13.16
Royalties	**(7.43)**	(3.06)	(1.82)
Operating costs	**(1.86)**	(1.93)	(2.21)
Operating netback ($	**25.80**	13.37	9.13

Kaybob



creased production from our Kaybob property by 31 percent ...ily to our undeveloped land position in the area. We also spent ... facilities to improve our operational flexibility. As a result, the ... plants via 3 alternative pipeline routes. ... lowering production by only 3 mmcf per day and reducing ... ybob area

We completed our first full year of production from the Fir pool, where we reached a peak production rate of 43 mmcf per day. Although the pool has begun to show signs of declines, it is too early to predict a decline rate. The Colt pool experienced high initial declines but is now showing signs of a stabilized rate.

The Kaybob drilling program targets medium-risk Viking and Gething reservoirs in the Cretaceous interval and the Blueridge and Wabamum reservoirs in the deeper and riskier, but high-potential Devonian interval.

Although the Devonian drilling program did not yield any significant successes in 2000, it did result in a number of uphole Cretaceous gas wells. As a result of our successes in the Cretaceous, we have established an even more aggressive drilling program in 2001, with a well-defined prospect inventory.

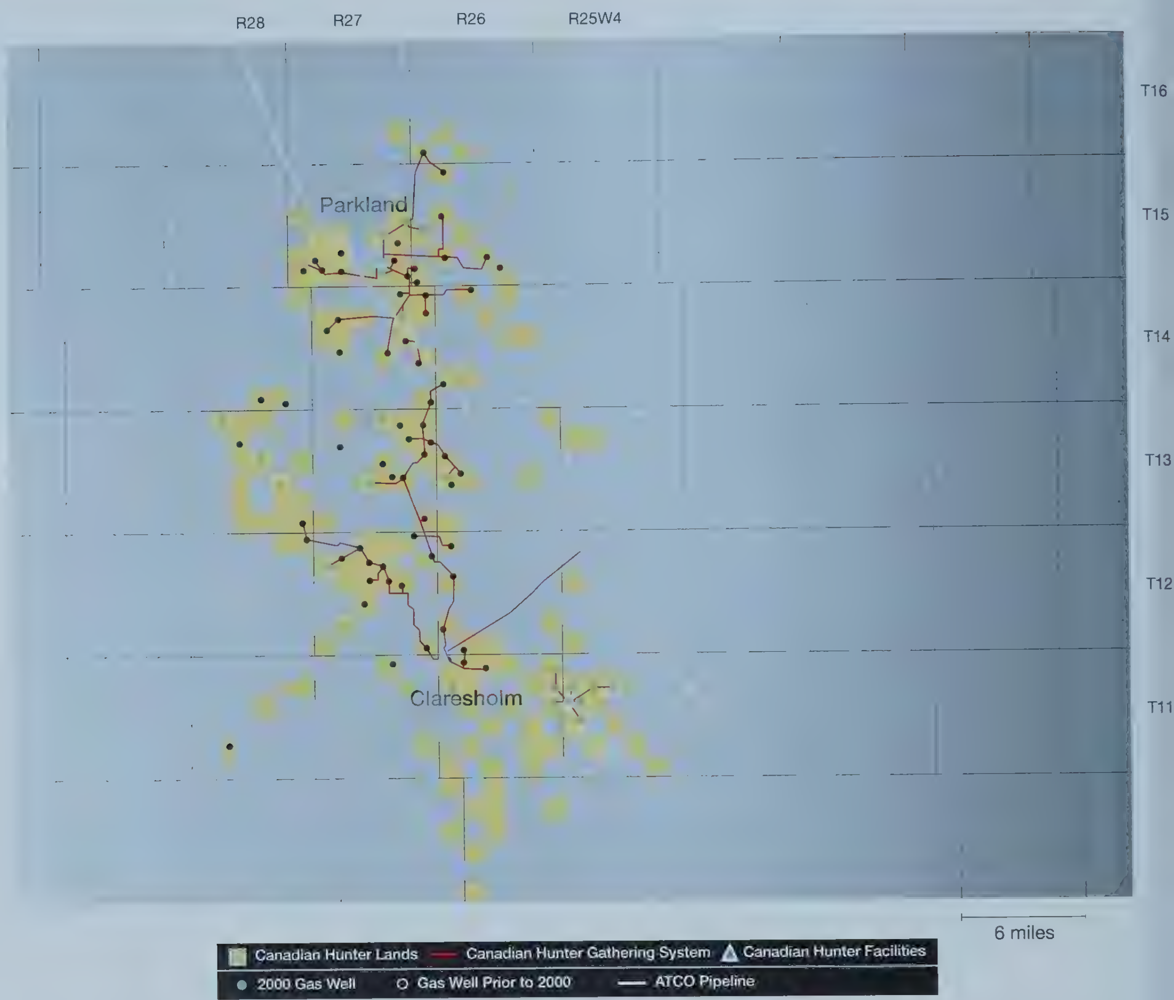
Wells in this area average from 2,300 to 3,400 metres in depth and cost approximately $650,000 and $2.5 million to drill and complete for the Cretaceous and Devonian zones respectively. Initial production rates range from 2 mmcf per day in the Cretaceous to over 30 mmcf per day from the Devonian reservoirs. Reserves per well reflect a similar range of 2 to 20 bcf.

In addition to the associated geological risk, Kaybob is a high operating cost area with average costs of between $0.75 and $0.95 per mcf of sales gas due to processing fees for sour gas at non-owned plants. To reduce operating costs and improve the economics in this area, we are considering building a stand-alone sour gas re-injection facility.

In 2001, we will spend roughly $50 million in the Kaybob area. The drilling program will target about 12 Devonian wells stacked with uphole potential, plus an additional 20 Cretaceous wells.

	2000	1999	1998
Land position			
Total net acres (000s)	**282**	174	126
Net undeveloped acres	**263**	111	86
Well information			
Wells drilled (GROSS/NET)	**20/12**	16/11	11/6
Exploration/development	**80/20**	89/11	64/36
Success rate (%) (GROSS/NET)	**85/88**	81/80	91/84
Average production			
Natural gas (mmcf/d)	**42**	33	11
Natural gas liquids	**476**	197	209
Crude oil (bbls/d)	**7**	–	–
Total (boe/d)	**7,402**	5,639	2,091
Capital expenditures (exploration & development)	**41.6**	42.4	35.3
Operating income ($ MILLIONS)	**56.2**	18.0	7.4
Reinvestment ratio (%)	**74**	236	477
Netback ($/b			
Price	**32.69**	16.31	14.12
Royalties	**(6.77)**	(1.79)	(0.40)
Operating costs	**(5.17)**	(5.80)	(4.65)
Operating netback	**20.75**	8.72	9.07

Claresholm/Parkland



[illegible] property acquisition in the Claresholm/Parkland area added 2 mmcf [illegible]ction, a small gas plant, and 35 sections of high potential land. An [illegible]ctions of exploratory land were purchased at Crown sales.

Our drilling program targets the Glauconite and Cutbank formations in the Cretaceous interval at an average depth of 2,400 metres. Wells in this area cost $750,000 on average to drill and complete. A typical well provides initial production of 1.5 mmcf per day and average reserves of 1.5 bcf. First year decline rates for these wells average 25 percent.

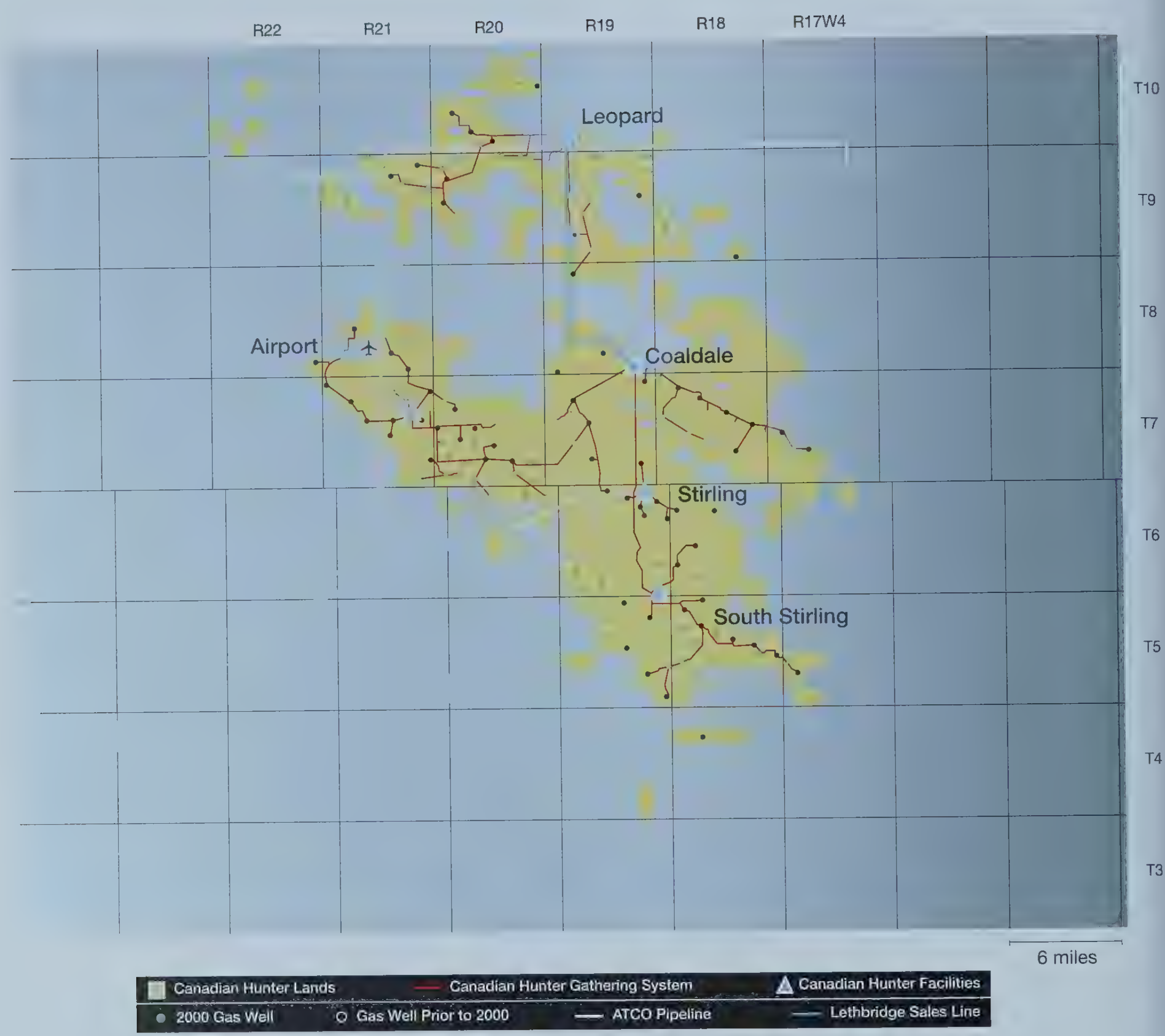
Low operating costs of $1.29 per boe contribute to our high netbacks in this area. Major infrastructure already exists in this area, so economics are very attractive for future drilling.

Our focus in 2001 is to explore this expanded land base with a balanced drilling program of exploration and development wells. In addition, we plan to expand the boundaries of this property with higher risk, higher impact exploration wells. The overall plan for Claresholm includes a $15 million, 15 well drilling program.

We drilled a number of higher impact wells in this area during the fourth quarter of 2000, one of which came onstream in January 2001 at an initial rate of 13 mmcf per day. This is a much higher rate than the average well in the area, contributing to the record production of 44 mmcf per day recently achieved in this 6 year old property.

	2000	1999	1998
Land position			
Total net acres (000s	153	81	93
Net undeveloped acres	100	12	47
Well information			
Wells drilled (GPC	18/14	19/17	14/10
Exploration/development	100/0	79/21	58/42
Success rate	67/72	68/70	79/75
Average production			
Natural gas	34	34	25
Natural gas liquids	199	167	191
Crude oil (bbls/d)	8	10	5
Total	5,898	5,858	4,436
Capital expenditures (exploration & development)	14.6	15.0	11.6
Operating income ($ Mil	52.5	25.2	14.9
Reinvestment ratio	28	60	78
Netback ($/boe)			
Price	33.38	16.88	13.09
Royalties	(7.79)	(3.77)	(2.64)
Operating costs	(1.29)	(1.32)	(1.23)
Operating netback	24.30	11.79	9.22

Lethbridge



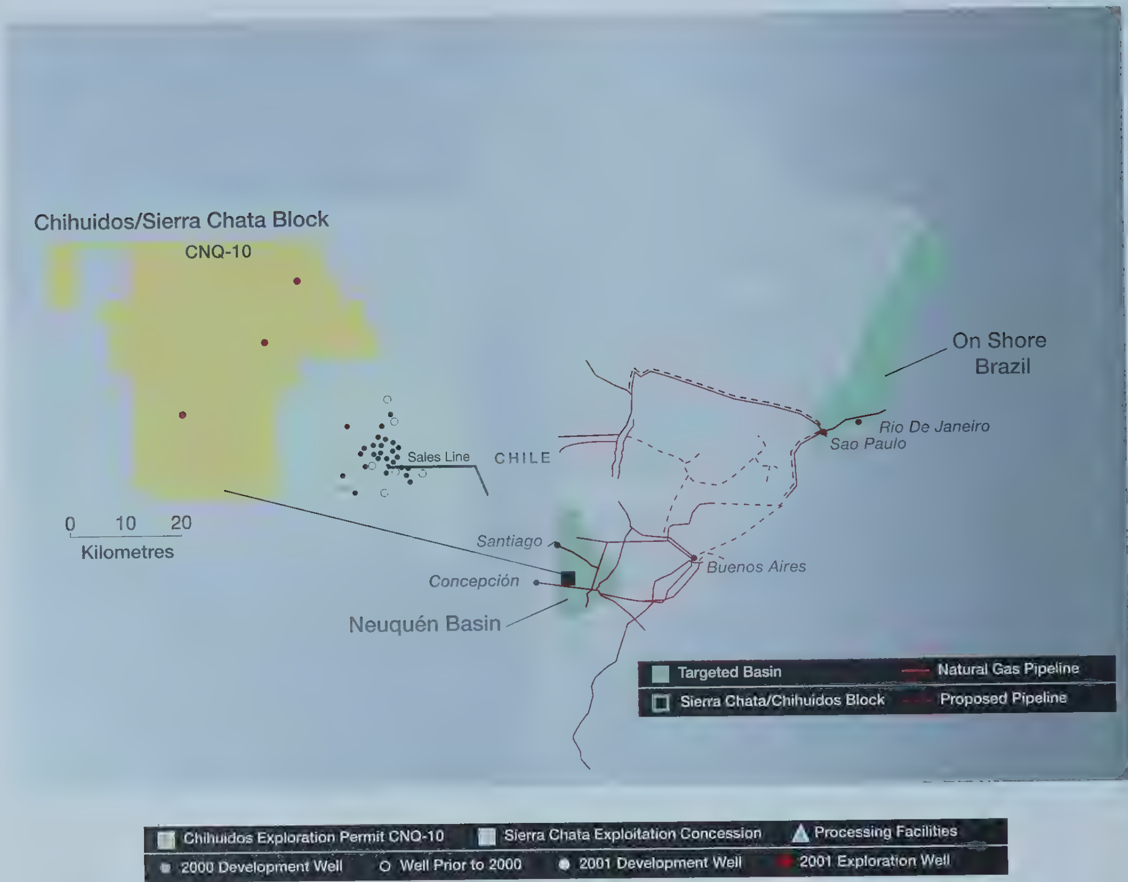
arge, undeveloped land base in our low-risk Lethbridge area,
ugh a large area farm-in. Average wells in this area cost
rill and complete and initial production rates average just
uring 2000, we drilled 103 net wells and added production
ted gas plants, growing net production from the area to 45 mmcf

Our drilling program in Lethbridge targets the gas-prone Bow Island formation, at an average depth of 900 metres. Payout on capital is short, due to high initial deliverability of these shallow gas pools. Despite high first year decline rates, these wells are economically attractive over the long term. The play is enhanced by very low operating costs.

Expenditures on facilities accounted for 50 percent of total capital deployed in this area in 2000. Now, with 5 Canadian Hunter-operated plants capable of processing 52 mmcf per day, and the ability to expand capacity quickly and at low cost, we effectively control development in the region. Our extensive infrastructure combined with a large undeveloped land base makes future drilling economics attractive.

In 2001, Canadian Hunter plans to spend $17 million and will drill approximately 60 wells in Lethbridge. In addition to drilling shallow development wells to maintain production at the 52 mmcf per day plant capacity level, we plan to drill deeper exploration targets in the area.

	2000	1999	1998
Land position			
Total net acres (000S)	**265**	143	46
Net undeveloped acres (000S)	**183**	96	38
Well information			
Wells drilled (GROSS/NET)	**106/103**	61/59	11/11
Exploration/development (%)	**97/3**	95/5	100/0
Success rate (%) (GROSS/NET)	**88/88**	84/84	82/82
Average production			
Natural gas (mmcf/d)	**23**	4	–
Natural gas liquids (bbls/d)	**–**	–	–
Crude oil (bbls/d)	**–**	–	–
Total (boe/d)	**3,900**	701	–
Capital expenditures (exploration & development)	**52.1**	27.2	4.2
Operating income ($ MILLIONS)	**36.9**	3.0	–
Reinvestment ratio (%)	**141**	907	–
Netback ($/boe)			
Price	**32.94**	16.26	–
Royalties	**(6.37)**	(3.08)	–
Operating costs	**(0.72)**	(1.57)	–
Operating netback ($/boe)	**25.85**	11.61	–



international investment and acquired
talaya Energy S.A. ("Atalaya") for $54.5 million. Atalaya's
hihuidos Exploration permit and the Sierra
in the Neuquén Basin of Argentina. We then
cember 2000, with the acquisition of an additional
st in the property from Sociedad Internacional Petrolera

Canadian Hunter currently has an effective 23.5 percent working interest; other partners include Petrolera Sante Fe S.A. as operator, Exxon Mobil Corp. and Total Austral S.A. We have an offer outstanding to purchase the remaining 22 percent of Atalaya in September of 2001, which would increase our overall interest in the block to 25.7 percent.

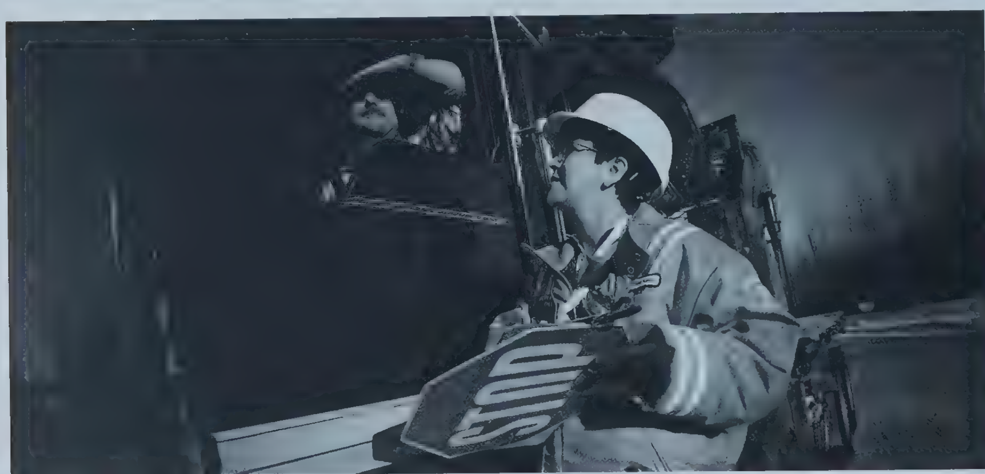
Sixty-three percent of the gas from the field is contracted to the Chilean market through to 2013. The remainder is sold into domestic markets in Argentina. Sales into the expanding Brazilian market will be possible once construction has been completed on a pipeline accessing that market from Argentina.

During the year Canadian Hunter spent $7 million of exploration and development capital on the Argentine property. We participated in 6 natural gas wells, acquired and reprocessed 2D and 3D seismic data and improved operational capabilities in the gas processing facility.

In addition to the existing reserve and production base, there is a large, undeveloped land position that we believe has substantial exploration potential.

In 2001, we plan to spend $10 million net to Hunter in the Sierra Chata and Chihuidos blocks, drilling 6 development wells and 3 exploration wells. We anticipate our net production from Sierra Chata will be approximately 30 mmcf per day of natural gas and 165 bbls per day of natural gas liquids. Canadian Hunter continues to pursue other opportunities in Argentina and Brazil, with a focus on quality assets and exploration potential with an operated position.

	2000	1999	1998
Land position			
Total net acres (000S)	568	–	–
Net undeveloped acres	95	–	–
Well information			
Wells drilled (GROSS/NET)	6/1	–	–
Exploration/development	0/100	–	–
Success rate (%) (GROSS/NET)	100/100	–	–
Average production			
Natural gas (mmcf/d)	14	–	–
Natural gas liquids (bbls/d)	76	–	–
Crude oil (bbls/d)	–	–	–
Total (boe/d)	2,335	–	–
Capital expenditures (exploration & development)	7.1	–	–
Operating income ($ MILLIONS)	9.2	–	–
Reinvestment ratio (%)	77	–	–
Netback ($/boe)			
Price	13.74	–	–
Royalties	(1.63)	–	–
Operating costs	(2.86)	–	–
Operating netback	9.25	–	–



Today a large herd of wood bison graze along the pipeline right-of-ways within Canadian Hunter's Border operations. Our sponsorship of the Wood Bison Recovery Program, a creative initiative to reestablish an endangered species, is operated in partnership with the Doig River First Nations and B.C. Environment.

Our Community

ENVIRONMENTAL, HEALT

EH&S services at Canadian Hunter focus on sound planning, liability management, employee and contractor education, and keeping Canadian Hunter among the energy industry leaders in EH&S protection. Our ongoing EH&S challenges include managing greenhouse gases to address global climate change, ensuring pressure equipment and pipeline integrity, reclaiming wellsites and flare pits, ensuring compliance with provincial and federal regulations, and addressing provincial land-use policies that affect exploration activities.

Canadian Hunter has developed an EH&S management system with the key elements being policy and commitment, protection planning, implementation and operation, auditing and reporting and review. Canadian Hunter continuously strives to improve its EH&S performance. Over the past number of years, several of Canadian Hunter's production facilities have received safety awards from the Canadian Gas Processors Association for a high number of man-hours without a lost time incident.

The Canadian Association of Petroleum Producers (CAPP) has implemented a voluntary EH&S Stewardship Program. The Stewardship Program creates standards with respect to regulatory issues and helps in the management of industry-landowner relationships. Canadian Hunter was one of the first companies to become involved in this new CAPP initiative and is committed to achieve a performance at the highest level in the Stewardship Program.

COMMUNITY SPIRI

The employees of Canadian Hunter have had a long track record of helping to improve the quality of life in communities in Alberta and British Columbia. Our commitment to corporate leadership has evolved into a company-wide ethic of community support, service and leadership. Many employees volunteer with numerous community, cultural, sport, educational, health and social service organizations, often in leadership roles. Hunter employees have also demonstrated generous financial support for a variety of organizations. One example of this generosity is the participation by nearly 100 percent of Canadian Hunter employees in the 2000 United Way Campaign. In recognition of the number of employees contributing as Leaders of the Way last year, Canadian Hunter received a Leadership Award.

On a corporate level, Canadian Hunter provides support and financial assistance for important community projects and initiatives in education, health, social service, cultural endeavors, community and civic activities.

This discussion and analysis of the financial condition and results of operations by the management of Canadian Hunter Exploration Ltd. ("Canadian Hunter", or the "Corporation") is to be read in conjunction with its audited consolidated financial statements for the fiscal years ended December 31, 2000 and December 31, 1999 (the "Financial Statements").

On March 1, 2000, the Corporation acquired 78 percent of Atalaya Energy S.A. ("Atalaya"), a company engaged in the exploration and development of natural gas and liquids in Argentina, for $55 million as described in Note 2 to the audited consolidated financial statements. Canadian Hunter's results of operations includes the Atalaya results from the effective date acquired.

On December 22, 1999, the Corporation acquired Kintail Energy Inc. ("Kintail"), an upstream exploration and production company with operations entirely in Canada, for $41 million as described in Note 2 to the Financial Statements. The Corporation's results of operations include the Kintail results from the effective date acquired.

- Production up 20 percent to 81,104 boe per day
- Funds from operations up 143 percent to $593 million
- Net income up 203 percent to $208 million
- Natural gas price up 91 percent to $4.96 per mcf
- Natural gas represented 88 percent of total production
- Net capital expenditures up 70 percent to $479 million
- Proven reserves up 23 percent to 212 mmboe

Equivalents

All calculations converting natural gas to a crude oil equivalent have been made using a ratio of 6 thousand cubic feet of natural gas to 1 barrel of crude oil. Comparable calculations using a 10 to 1 conversion are included in the Conversion Rate Comparison Table on page 59 of this Annual Report.

Financial Summary

($ MILLIONS)	2000	1999	1998
Net income	**207.7**	68.5	26.7
Funds from operations	**593.1**	244.4	156.2
Petroleum and natural gas sales	**909.3**	400.5	266.2
Net income ($ PER FULLY DILUTED SHARE)	**3.37**	1.12	0.45
Funds from operations ($ PER FULLY DILUTED SHARE)	**9.56**	3.97	2.62
Average shareholders' equity ($ MILLIONS)	**517.1**	381.8	316.7
Return on equity (%)	**40**	18	8
Return on capital employed (%)	**35**	12	6

Consolidated net income increased 203 percent in 2000. Consolidated funds from operations increased 143 percent. Consolidated petroleum and natural gas sales increased 127 percent. These increases are due to a combination of higher production and an exceptionally strong price environment for all commodities.

Consolidated funds

	$ MILLIONS	$/FULLY DILUTED SHARE	% CONTRIBUTION
1999 Funds from operations	**244.4**	**3.97**	
Production increases	78.2	1.25	22
Price increases	430.6	6.91	124
Operating costs	(7.9)	(0.13)	(2)
Royalties	(126.7)	(2.04)	(36)
Expensed G&A	(6.9)	(0.11)	(2)
Interest	(9.6)	(0.15)	(3)
Tax	(9.5)	(0.15)	(3)
Other	0.5	0.01	–
Net increase	348.7	5.59	100
2000 Funds from operations	**593.1**	**9.56**	–

This table shows a reconciliation of the change in funds from operations between 1999 and 2000. Higher natural gas prices and natural gas production drove cash flow to record levels, but were partially offset by increases in royalties.

Production

	CANADA 2000	CANADA 1999	CANADA 1998	ARGENTINA 2000	ARGENTINA 1999	ARGENTINA 1998	TOTAL CORPORATE 2000	TOTAL CORPORATE 1999	TOTAL CORPORATE 1998
Natural gas (mmcf/d)	**416**	357	288	**14**	–	–	**430**	357	288
Natural gas liquids (bbls/d)	**7,992**	6,216	5,439	**76**	–	–	**8,068**	6,216	5,439
Crude oil (bbls/d)	**1,376**	1,965	2,577	**–**	–	–	**1,376**	1,965	2,577
Total equivalent production (boe/d)	**78,769**	67,721	56,022	**2,335**	–	–	**81,104**	67,721	56,022

The Corporation achieved a record 430 mmcf per day of natural gas production in 2000, up 20 percent from 1999 primarily as a result of new production at Lethbridge (up 19 mmcf per day), two acquisitions in Argentina (14 mmcf per day), and excellent drilling results in the Deep Basin (up 14 mmcf per day), Border (up 13 mmcf per day), and Kaybob (up 9 mmcf per day) producing areas.

Canadian Hunter also produced 8,068 bbls per day of natural gas liquids and 1,376 bbls per day of oil in 2000. Natural gas liquids volumes increased 30 percent from 1999 as a result of higher natural gas production in the Deep Basin and Border areas. Oil production dropped 30 percent from 1999, due in part to the normal decline of the Brassey and Chedderville fields.

Total 2000 production increased 20 percent to 81,104 boe per day, with natural gas representing 88 percent of the product mix, natural gas liquids 10 percent, and crude oil representing the remaining 2 percent.

	CANADA			ARGENTINA			TOTAL CORPORATE		
	2000	1999	1998	**2000**	1999	1998	**2000**	1999	1998
Natural gas ($/mcf)	**5.06**	2.60	2.07	**2.13**	–	–	**4.96**	2.60	2.07
Natural gas liquids ($/bbl)	**36.39**	18.90	13.73	**42.84**	–	–	**36.46**	18.90	13.73
Crude oil ($/bbl)	**34.64**	26.01	22.88	**–**	–	–	**34.64**	26.01	22.88

Canadian Gas Sales Portfolio

2000

2001E

Aggregators
Discretionary
Fixed
Prepaid

Natural Gas – Canada

In 2000, Canadian Hunter's marketing activities resulted in an average price of $5.06 per mcf at the plant gate. This is significantly higher than the "Alberta Reference Price", an average sales price for all Alberta-based production. With the increased demand across North America, and reduced natural gas supply, North American natural gas prices have been driven much higher. Canadian Hunter's high working interests in producing wells and infrastructure provide flexibility to control volumes and enable the Corporation to access a variety of markets. Canadian Hunter manages a large portfolio of contracts involving a variety of markets. Canadian Hunter was well positioned in 2000 to capture higher prices, with 49 percent of its natural gas portfolio tied directly to the Alberta market. In 2001, Canadian Hunter expects to sell approximately 31 percent of its natural gas production to aggregators under long-term contracts and 65 percent under indexed contracts on a discretionary basis, responding to changing market conditions. The remaining 4 percent has been hedged at a fixed price.

Natural Gas – Argentina

In 2000, natural gas from Argentina was sold at an average realized price of $2.13 per mcf. The natural gas market in South America is not physically connected and therefore quite distinct from North American markets, so natural gas prices cannot be directly compared. Gas from the Sierra Chata field is contracted 63 percent to the Chilean market through to 2013 and 32 percent to the Argentine market through to 2001. The remaining 5 percent is sold on the spot market. Negotiations are underway to replace the expiring Argentine term contract.

Oil and Natural Gas Liquids

Oil and natural gas liquids prices were up in 2000 in response to strong world oil prices. Canadian Hunter's natural gas liquids price averaged $36.46 per bbl, up 93 percent over 1999, and the oil price averaged $34.64 per bbl, up 33 percent from 1999.

Canadian Hunter markets Canadian crude oil under a variety of contracts of up to one year in term. Natural gas liquids are left in the natural gas stream or sold as natural gas liquids depending on relative pricing. All natural gas liquids contracts are no longer than 1 year in term.

Pipeline Commitments

	FIRM CAPACITY COMMITMENT MMCF/D	TERM OF COMMITMENT
Alliance Pipeline Ltd.	50	November 30, 2015
PG&E – Northwest Division	20	November 1, 2001 to October 31, 2023
TCPL (B.C.) and NGTL Delivery	20	November 1, 2001 to October 31, 2008
TCPL (NGTL Delivery) and TCPL Mainline	20	October 31, 2008
TCPL (Alta) Receipt Capacity	147	Variable
ATCO North and ATCO South	65	1 year

This table outlines the Corporation's firm pipeline capacity commitments which, in combination with other interruptible transportation arrangements, should be adequate to handle Canadian Hunter's gas production.

Revenue

	CANADA			ARGENTINA			TOTAL CORPORATE		
($ MILLIONS)	**2000**	1999	1998	**2000**	1999	1998	**2000**	1999	1998
Natural gas	**771.7**	339.1	217.5	**12.3**	–	–	**784.0**	339.1	217.5
Natural gas liquids	**106.4**	42.8	27.2	**1.4**	–	–	**107.8**	42.8	27.2
Crude oil	**17.5**	18.6	21.5	**–**	–	–	**17.5**	18.6	21.5
Gross production revenue	**895.6**	400.5	266.2	**13.7**	–	–	**909.3**	400.5	266.2

Gross production revenue increased 127 percent in 2000 due to a combination of higher natural gas production and an exceptionally strong price environment for all commodities. Revenue from natural gas represented 86 percent of the Corporation's total revenue in 2000. Natural gas liquids, a natural gas by-product, accounted for 12 percent of total revenue. The remaining 2 percent of revenue was sourced from crude oil, where higher prices were offset by lower production.

($ MILLIONS)	2000	1999	1998
Crown royalties	**176.3**	68.6	41.6
Freehold royalties and gross overriding royalties	**24.9**	6.4	3.6
	201.2	75.0	45.2
Alberta Royalty Tax Credit	**(0.7)**	(1.2)	(1.4)
Total royalties	**200.5**	73.8	43.8
Average corporate royalty rate	**22%**	18%	16%

Royalties are payments made to the owners of the mineral rights with whom Canadian Hunter holds leases. Crown royalties are paid to the provincial governments of Alberta and British Columbia in Canada, and the provincial government of Neuquén in Argentina. Freehold royalties are paid to freehold lease owners and gross overriding royalties are paid to other operators with whom Canadian Hunter holds joint interests. The Alberta Royalty Tax Credit is an incentive program designed to encourage oil and natural gas development in Alberta. Royalties averaged 22 percent of revenue, up from 18 percent in 1999, reflecting higher prices.

For Alberta natural gas production, the Corporation pays royalties based on the Alberta Reference Price. In Argentina, the average royalty rate is 12 percent.

	CANADA			ARGENTINA			TOTAL CORPORATE		
	2000	1999	1998	**2000**	1999	1998	**2000**	1999	1998
Natural gas	**0.32**	0.32	0.29	**0.49**	–	–	**0.32**	0.32	0.29
Natural gas liquids	**0.60**	1.69	0.61	**–**	–	–	**0.59**	1.69	0.61
Crude oil	**6.76**	4.47	2.83	**–**	–	–	**6.76**	4.47	2.83
Total operating costs ($/boe)	**1.85**	1.96	1.70	**2.86**	–	–	**1.88**	1.96	1.70

Canadian Hunter's operating costs remain among the lowest in the Canadian industry at $1.85 per boe, and were 6 percent lower than 1999. Inflationary pressures were offset by increased plant utilization, thereby lowering per unit operating costs. Operating costs for 2001 are expected to be approximately $2.00 per boe, but could go higher, depending on the extent to which electrical power costs increase in Alberta.

Natural gas liquids operating costs reflect only the portion of costs associated with the deep-cut processing facility where natural gas liquids are removed from the gas stream and sold as value-added products.

Declining production at Brassey and Chedderville led to increased per unit costs on crude oil.

Product Operating N

	CANADA 2000	1999	1998	ARGENTINA 2000	1999	1998	TOTAL CORPORATE 2000	1999	1998
Natural Gas ($/mcf)									
Revenue	**5.06**	2.60	2.07	**2.13**	–	–	**4.96**	2.60	2.07
Royalties	**(1.20)**	(0.50)	(0.36)	**(0.25)**	–	–	**(1.17)**	(0.50)	(0.36)
Operating costs	**(0.32)**	(0.32)	(0.29)	**(0.49)**	–	–	**(0.32)**	(0.32)	(0.29)
Operating netback	**3.54**	1.78	1.42	**1.39**	–	–	**3.47**	1.78	1.42
Royalties (%)	**24**	19	17	**12**	–	–	**24**	19	17
Natural Gas Liquids ($									
Revenue	**36.39**	18.90	13.73	**42.84**	–	–	**36.46**	18.90	13.73
Royalties	**(3.55)**	(1.58)	(1.08)	**(5.02)**	–	–	**(3.57)**	(1.58)	(1.08)
Operating costs	**(0.60)**	(1.69)	(0.61)	**–**	–	–	**(0.59)**	(1.69)	(0.61)
Operating netback	**32.24**	15.63	12.04	**37.82**	–	–	**32.30**	15.63	12.04
Royalties (%)	**10**	8	8	**12**	–	–	**10**	8	8
Crude Oil ($/bbl)									
Revenue	**34.64**	26.01	22.88	**–**	–	–	**34.64**	26.01	22.88
Royalties	**(9.84)**	(6.51)	(5.75)	**–**	–	–	**(9.84)**	(6.51)	(5.75)
Operating costs	**(6.76)**	(4.47)	(2.83)	**–**	–	–	**(6.76)**	(4.47)	(2.83)
Operating netback	**18.04**	15.03	14.30	**–**	–	–	**18.04**	15.03	14.30
Royalties (%)	**28**	25	25	**–**	–	–	**28**	25	25
Total Operating Netbacks									
Revenue	**31.07**	16.20	13.02	**13.74**	–	–	**30.49**	16.20	13.02
Royalties	**(6.90)**	(2.98)	(2.15)	**(1.63)**	–	–	**(6.72)**	(2.98)	(2.15)
Operating costs	**(1.85)**	(1.96)	(1.70)	**(2.86)**	–	–	**(1.88)**	(1.96)	(1.70)
Operating netback	**22.32**	11.26	9.17	**9.25**	–	–	**21.89**	11.26	9.17
Royalties (%)	**22**	18	17	**12**	–	–	**22**	18	17

Product operating netbacks represent the operating cash flow Canadian Hunter receives, on average, for each unit of product sold before interest and cash taxes. Natural gas liquids are a by-product of natural gas production. The netback for natural gas liquids is shown separately; however, most of the operating costs and a portion of the royalties for natural gas liquids are included with the natural gas production stream, and so the individual product netbacks are somewhat distorted. Natural gas netbacks in Canada increased 99 percent to $3.54 per mcf. In 2000, crude oil netbacks increased by 20 percent in response to increases in oil prices offset by higher royalties and unit operating costs. Higher production and prices pushed up the total Canadian netback from all products by 98 percent in 2000. Argentina gas receives a lower price per unit than Canadian gas. However, lower royalty rates partially offset lower prices, resulting in an attractive netback.

($/boe)	CANADA 2000	1999	1998	ARGENTINA 2000	1999	1998	TOTAL CORPORATE 2000	1999	1998
Operating netback	**22.32**	11.26	9.17	**9.25**	–	–	**21.89**	11.26	9.17
General and administrative expense	**(0.77)**	(0.70)	(0.54)	**(2.18)**	–	–	**(0.81)**	(0.70)	(0.54)
Interest expense	**(0.56)**	(0.27)	(0.43)	**(0.10)**	–	–	**(0.55)**	(0.27)	(0.43)
Current taxes	**(0.60)**	(0.31)	(0.43)	**–**	–	–	**(0.58)**	(0.31)	(0.43)
Cash netback	**20.39**	9.98	7.77	**6.97**	–	–	**19.95**	9.98	7.77

The cash netback represents the total cash flow Canadian Hunter receives on each unit of product sold, by deducting other cash costs from the operating netback.

($ MILLIONS)	2000	1999	1998
Gross expense	**35.6**	27.1	22.0
Less capitalized portion	**(11.3)**	(9.8)	(11.0)
Net general and administrative expense	**24.3**	17.3	11.0
($/boe)			
Gross expense	**1.19**	1.10	1.08
Less capitalized portion	**(0.38)**	(0.40)	(0.54)
Net general and administrative expense	**0.81**	0.70	0.54

Gross general and administrative costs on a per unit basis increased by 8 percent in 2000, as the Corporation expanded staff levels. Canadian Hunter capitalizes the portion of overhead costs that is associated with the capital spending program, and these costs are then included in the Corporation's finding and development cost calculation.

Oil and Gas Tax Pools
($MILLIONS)

CDE	58
UCC	185
COGPE	125
Argentina	114

In 2000, Canadian Hunter incurred income tax expense of $160.6 million. Current income taxes represented $15.0 million and large corporations tax accounted for $2.2 million. If commodity prices remain high, Canadian Hunter will likely incur significant current income taxes in 2001, dependent upon the level and nature of future capital expenditures.

Capital Expendi

($ MILLIONS)	2000	1999	1998
Lease acquisition and rentals	**75.0**	22.8	29.0
Seismic	**12.2**	13.1	4.6
Drilling and completions	**171.6**	128.8	105.0
Facilities	**86.9**	66.0	46.2
Capitalized general and administrative	**11.3**	9.8	11.0
Exploration and development expenditures	**357.0**	240.5	195.8
Acquisitions	**147.6**	48.3	14.6
Dispositions	**(30.5)**	(10.3)	(3.1)
Other	**4.7**	2.6	5.7
Total capital expenditures	**478.8**	281.1	213.0

Canadian Hunter's total capital expenditure program was 70 percent higher than in 1999, and was funded by a combination of internally generated cash flow and an increase in long-term debt of $75 million. Exploration and development expenditures increased by 48 percent.

The focus of increased expenditures in 2000 was on new exploration lands. The undeveloped land position was increased by 29 percent to 1.9 million acres of net undeveloped land. Canadian Hunter also participated in one of the most active drilling programs in its history. Canadian Hunter drilled 25 percent more wells in 2000, with a total of 332 gross wells (271 net) drilled, compared to 266 gross wells (196 net) in 1999, with a success ratio of 85 percent (85 percent net). Exploration wells accounted for 72 percent of the total wells drilled in 2000.

Canadian Hunter made two significant acquisitions in Argentina during 2000. The corporate acquisition of Atalaya provided a base of production and cash flow in Argentina. That was followed up with the acquisition of Sipetrol's interest in the same property.

A number of small property acquisitions were also made in Canada totaling $21 million. Total proceeds from minor property dispositions were $30.5 million.

Effectively 100 percent of Canadian Hunter's capital expenditures were directed toward natural gas projects in 2000. In 2001, none of the current capital budget is expected to be directed to oil development, and the capital budget is expected to be spread amongst a variety of properties, underlining the breadth of Canadian Hunter's opportunities.

In 2001, Canadian Hunter's exploration and development capital expenditure budget is expected to be funded by internally generated cash flow. The Corporation does not allocate a specific budget for acquisitions, as any transactions would be separately approved by the Board of Directors of Canadian Hunter.

...nciliation

	NATURAL GAS (bcf)	CRUDE OIL AND NGLS (mmbbls)	EQUIVALENT (mmboe)	% GAS
Canada				
January 1, 2000	914.9	20.3	172.8	88%
Discoveries and extensions	228.1	4.0	42.0	91%
Revisions of prior estimates	(15.8)	0.3	(2.3)	100%
Acquisitions/dispositions	(5.4)	–	(0.9)	100%
Production	(152.4)	(3.4)	(28.8)	88%
January 1, 2001	969.4	21.2	182.8	88%
Argentina				
January 1, 2000	–	–	–	–
Discoveries and extensions	–	–	–	–
Revisions of prior estimates	–	–	–	–
Acquisitions/dispositions	172.8	1.0	29.9	97%
Production	(5.0)	–	(0.9)	97%
January 1, 2001	167.8	1.0	29.0	97%

In Canada, proven reserves increased 6 percent, almost entirely through exploration and development drilling. When the Argentina acquisitions are included, the reserve base grows by 23 percent.

	NATURAL GAS (bcf)		CRUDE OIL AND NGLS (mmbbls)		EQUIVALENT (mmboe)	
AT JANUARY 1, 2001	GROSS	NET	GROSS	NET	GROSS	NET
Canada						
Developed producing	799.4	599.2	17.4	13.0	150.7	112.8
Developed non-producing	9.0	6.7	0.2	0.2	1.7	1.3
Undeveloped	161.0	122.3	3.6	2.6	30.4	23.0
Total proven	969.4	728.2	21.2	15.8	182.8	137.1
Risked probable	92.2	70.1	2.3	1.7	17.7	13.4
Argentina						
Developed producing	60.8	53.4	0.4	0.3	10.5	9.2
Developed non-producing	–	–	–	–	–	–
Undeveloped	107.0	93.9	0.6	0.6	18.5	16.2
Total proven	167.8	147.3	1.0	0.9	29.0	25.4
Risked probable	40.1	35.2	0.2	0.2	6.9	6.1
Total Corporate						
Developed producing	860.2	652.6	17.8	13.3	161.2	122.0
Developed non-producing	9.0	6.7	0.2	0.2	1.7	1.3
Undeveloped	268.0	216.2	4.2	3.2	48.9	39.2
Total proven	1,137.2	875.5	22.2	16.7	211.8	162.5
Risked probable	132.2	105.3	2.5	1.9	24.6	19.5

Net Present Value

($MILLIONS BEFORE TAX)	CANADA (CDN$) 0%	10%	15%	20%	ARGENTINA (US$) 0%	10%	15%	20%
Proven								
Developed producing	2,955.3	2,161.0	1,941.8	1,776.8	53.0	38.6	34.1	30.7
Developed non-producing	35.3	26.7	24.1	22.0	–	–	–	–
Undeveloped	510.6	297.5	251.8	219.9	118.5	61.4	46.9	36.7
Total proven	3,501.2	2,485.2	2,217.7	2,018.7	171.5	100.0	81.0	67.4
Risked probable	285.4	165.1	136.1	115.8	43.7	12.8	7.4	4.5
Total proven plus risked probable	3,786.6	2,650.3	2,353.8	2,134.5	215.2	112.8	88.4	71.9

Capital Efficien

	CANADA 2000	1999	1998	ARGENTINA 2000	1999	1998	TOTAL CORPORATE 2000	1999	1998
Finding and development costs									
Finding and development	**8.82**	4.70	5.45	**–**	–	–	**9.00**	4.70	5.45
Finding, development and acquisition	**8.78**	4.95	5.60	**4.48**	–	–	**6.91**	4.95	5.60
Reserve replacement									
E&D only	**138**	207	176	**–**	–	–	**134**	207	176
Total including net acquisitions	**134**	228	181	**3,490**	–	–	**231**	228	181
Capital reinvestment ratio									
E&D only	**60**	98	125	**98**	–	–	**60**	98	125
Total including net acquisitions	**59**	115	136	**1,836**	–	–	**81**	115	136
Recyle ratio									
Cash netback ÷ F&D cost	**2.3**	2.1	1.4	**–**	–	–	**2.2**	2.1	1.4
Cash netback ÷ FD&A cost	**2.3**	2.0	1.4	**1.6**	–	–	**2.9**	2.0	1.4

Depletion, Depr

($/boe)	2000	1999	1998
Depletion	**6.16**	5.61	5.41
Depreciation	**0.11**	0.12	0.28
Reclamation	**0.20**	0.24	0.22
Deletion, depreciation and amortization rate	**6.47**	5.97	5.91

Depletion, depreciation and amortization ("DD&A") provided on the unit of production method is based on total proven reserves with conversion of natural gas to oil using relative energy content. Undeveloped land value is included in the depletion calculation. DD&A for the year increased to $192.8 million in 2000 from $147.5 million in 1999, mainly as a result of higher finding and development costs coupled with increased capital associated with the acquisition of 78 percent of Atalaya.

As at December 31, 2000, Canadian Hunter had long-term debt outstanding of $235 million, an increase of 46 percent over 1999. Debt to trailing cash flow has decreased to 0.4. Canadian Hunter currently has unsecured credit facilities totaling $500 million from four major banks, with a revolving term which may be converted into an amortizing term at the Corporation's discretion. The unutilized credit facilities, combined with very low debt ratios, ensure that Canadian Hunter will continue to have the financial resources to execute its strategy.

Total interest expense increased to $16.4 million in 2000, compared to $6.7 million in 1999. The average gross rate of interest paid by the Corporation during the year was 6.21 percent, compared to an average rate of 5.55 percent paid in 1999. Other financing charges of $48.6 million were incurred in 2000 due to the loss on termination of a prepaid natural gas contract, as described in Notes 5 and 6 to the Financial Statements.

Canadian Hunter is exposed to a number of risks inherent in exploring for, developing, producing and marketing oil and natural gas. These risks include the following:

Exploration and Development Risk

The ability to find and develop economic oil and natural gas reserves to replace existing production and create value for Canadian Hunter shareholders is paramount to the Corporation's success. Canadian Hunter is impacted by intense competition for land, for experienced drilling crews and for experienced technical professionals. Canadian Hunter employs a number of highly skilled professionals with experience in the Corporation's areas of activity. In addition, Canadian Hunter attempts to manage risk by maintaining a portfolio of high, medium and lower risk exploration prospects.

Operational Risk

Production is processed at both Canadian Hunter operated and non-operated production facilities. Production is sometimes temporarily curtailed due to both scheduled and unscheduled facility maintenance and upgrading.

Transportation Risk

Canadian Hunter transports its products via third party pipelines. Curtailments occasionally occur that are beyond our control.

Environmental, Health and Safety Risk

Canadian Hunter is committed to operating in an environmentally sensitive manner and to safeguarding the health and safety of the Corporation's employees, contractors and the public. The Corporation also completes a rigorous screening of its operations to ensure safe, efficient activities at all Canadian Hunter job sites.

Kyoto Protocol on Greenhouse Gas Emissions

Canada is signatory to an international treaty to reduce greenhouse gas emission levels. While the Corporation is actively participating in programs to reduce its greenhouse gas emissions, at this time it is unclear as to the course of action the Canadian or United States governments will take in this regard if the overall treaty goal is not achieved. Accordingly, the Corporation cannot measure the potential risk to its business.

Access to Land

Uncertainty associated with accessing public lands for oil and gas exploration continues to persist. Although there is more definition of protected area boundaries within British Columbia and Alberta, there are questions concerning the development of new overlapping federal endangered species legislation, which could restrict development in some areas. There are also new concerns with respect to industry access to First Nation traditional lands in British Columbia and Alberta. Canadian Hunter will continue to participate in land-use planning processes and work with all stakeholders.

Financial Risk

As part of the normal course of business, Canadian Hunter is exposed to a variety of financial risks. It is the objective of the Corporation to manage financial risks with natural hedges whenever possible. However, financial instruments will be used when it can be demonstrated that their use will either reduce risk or modify risk.

Foreign Exchange Risk

Canadian Hunter is potentially exposed to foreign currency fluctuations, which create transaction, translation and economic exposures.

Transaction exposure refers to the gains or losses that could potentially be incurred as a result of changes in foreign exchange rates from the time a transaction is contemplated or committed to when the transaction is settled.

Translation exposure refers to the variation of the value of assets, liabilities, revenues, and expenses recorded in the financial statements in Canadian dollars but denominated in foreign currencies. Exchange gains and losses from the translation of the financial statements of self-sustaining foreign operations are disclosed as a component of shareholders' equity and have no effect on earnings.

It is one of the Corporation's objectives to reduce its exposure to fluctuating foreign exchange rates when those fluctuations have a negative impact on earnings by managing the spot and rate differential associated with its foreign exchange exposure.

Economic exposure refers to the true economic risk faced by the Corporation's businesses resulting from the impact currency fluctuations may have on the markets, customers and/or competitors. These economic risks are not normally hedged.

Interest Rate Risk

Canadian Hunter is potentially exposed to interest fluctuations as a result of its borrowing requirements. Another of the Corporation's objectives is to reduce its exposure to fluctuating interest rates when those fluctuations have a negative impact on earnings by managing the duration, liquidity and interest costs associated with its debt portfolio.

Commodity Price Risk

The sales prices received for Canadian Hunter's products are subject to fluctuations in world oil markets and North American natural gas markets. Canadian Hunter has over 50% of its forecast 2001 natural gas production tied to spot market prices.

In addition to the limits established by the Board of Directors, the marketing group must have each hedging transaction approved by both the President and Chief Executive Officer and the Chief Financial Officer.

The Corporation's net income and funds from operations are highly sensitive to changes in factors that are beyond its control. The following table illustrates the estimated impact of these changes on Canadian Hunter's 2001 funds from operations and net income.

CHANGE OF:	FUNDS FROM OPERATIONS $ MILLIONS	FUNDS FROM OPERATIONS $/FULLY DILUTED SHARE	NET INCOME $ MILLIONS	NET INCOME $/FULLY DILUTED SHARE
$0.10/mcf in natural gas price	7.2	0.12	7.2	0.12
US$1.00/bbl in the WTI crude oil price	1.3	0.02	1.3	0.02
1% in short-term interest rates	0.6	0.01	0.6	0.01

2001 Outlook

Canadian Hunter's outlook on the Canadian natural gas sector remains positive. We anticipate the current tight balance between natural gas supply and demand in North America will support favourable prices for some time. We have a large inventory of quality exploration and development opportunities in our core areas in western Canada and in Argentina. We are not opportunity limited. While increasing industry activity is likely to drive up costs, capital spending discipline and cost control will remain priorities as we continue to build value for our 30,000 shareholders.

With our leverage to natural gas, we are well-positioned to take advantage of this favourable price environment. Annual natural gas production is expected to grow a further 14 percent in 2001. The 2001 total production forecast is broken down in the following table:

2001 Production

	CANADA	ARGENTINA	TOTAL
Natural gas (mmcf/d)	460	30	490
Natural gas liquids (bbls/d)	8,800	165	8,965
Crude oil (bbls/d)	1,200	–	1,200
Barrel of oil equivalent [illegible]	86,820	5,175	91,995
Barrel of oil equivalent [illegible]	56,000	3,165	59,165

The table above outlines Canadian Hunter's current best estimate of 2001 production, which is entirely from internally generated exploration and development prospects. Any acquisitions could provide additional production growth.

An exploration and development capital budget of $385 million for Canada and $10 million for Argentina has been approved by Canadian Hunter's Board of Directors for 2001.

Reserves Evaluation

To the Shareholders of Canadian Hunter Exploration Ltd.

This letter is to confirm that Sproule Associates Limited was retained as an independent consultant to evaluate the petroleum and natural gas reserves of Canadian Hunter Exploration Ltd.

Sproule Associates Limited has prepared a report dated January 26, 2001, entitled "Evaluation of the Petroleum and Natural Gas Reserves of Canadian Hunter Exploration Ltd., as of January 1, 2001", and a report dated March 8, 2001 entitled "Evaluation of the P&NG Reserves of Canadian Hunter Exploration Ltd. in the Sierra Chata Field, Argentina as of January 1, 2001", which present the results of this evaluation. These reports have been prepared in accordance with the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Examinations were made in accordance with generally accepted engineering standards and included such tests and other procedures as were considered necessary.

The accuracy of reserves evaluated and associated economic analysis is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. The estimates presented were considered reasonable at the time this report was prepared. However, they should be accepted with the understanding that reservoir performance subsequent to the date of the estimates may necessitate revision.

In our opinion, our reports (including 44 percent of the Corporation's petroleum and natural gas reserves in Canada that were re-calculated from last year) present fairly, in all material respects, the reserves and resulting cash flows and net present values of Canadian Hunter Exploration Ltd.'s reserves, as at January 1, 2001.

Sproule Associates Limited
Calgary, Canada
March 8, 2001

A summary of the reports of Sproule Associates Limited is included in Canadian Hunter's Annual Information Form for fiscal 2000.

Management's Report on the Financial Statements and Financial Presentation

The accompanying audited consolidated financial statements and other financial information have been prepared by Canadian Hunter's management who is responsible for the integrity and objectivity of the financial statements. Management has implemented systems of internal control to provide reasonable assurance that all transactions are properly authorized, assets are safeguarded and financial records are maintained to facilitate the preparation of reliable and timely consolidated financial statements.

The financial statements have been prepared in conformity with generally accepted accounting principles and, where appropriate, reflect estimates based on management's judgment. The financial information presented throughout this Annual Report is consistent with the information contained in the accompanying consolidated financial statements.

Ernst & Young LLP, Chartered Accountants, the Corporation's independent auditors, examined the financial statements in accordance with auditing standards generally accepted in Canada to enable them to express to the shareholders their opinion on the financial statements. Their report as auditors in that regard is set out on page 40 of this Annual Report.

The financial statements have been further examined by the Board of Directors and by its Audit Committee. The auditors have direct and full access to the Audit Committee and meet with the committee both with and without the presence of management. The Board of Directors, through its Audit Committee, oversees management's financial reporting responsibilities and is responsible for reviewing and approving the financial statements.

Stephen J. Savidant
President and
Chief Executive Officer

Calgary, Canada
March 5, 2001

Stephen B. Soules
Senior Vice President,
Chief Financial Officer and
Corporate Secretary

Auditors' Report

To the Shareholders of Canadian Hunter Exploration Ltd.

We have audited the consolidated balance sheets of Canadian Hunter Exploration Ltd. (the "Corporation") as at December 31, 2000 and 1999, and the consolidated statements of net income and retained earnings and cash flow for the years then ended. These consolidated financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We have conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Corporation as at December 31, 2000 and 1999, and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in Canada.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Calgary, Canada
February 2, 2001

Consolidated Balance Sheets

(THOUSANDS OF DOLLARS

AS AT DECEMBER 31	2000	1999
Assets		
Current		
Accounts receivable	212,777	64,082
Inventories	18,948	3,612
Other current assets (NOTE 3)	3,351	2,635
	235,076	70,329
Other assets (NOTE :	33,064	24,545
Property, plant and equipment	1,252,484	935,357
	1,520,624	1,030,231
Liabilities		
Current		
Accounts payable and accrued liabilities	180,164	96,523
Income taxes payable	19,909	5,709
Current portion of deferred revenue and other liabilities	4,256	8,475
	204,329	110,707
Deferred revenue and other liabilities	52,266	104,213
Long-term debt (NOTE 6	234,883	160,379
Future income tax liability	397,060	238,924
Minority interest	13,998	–
	902,536	614,223
Shareholders' Equit		
Share capital (N	347,638	347,520
Retained earnings	270,445	68,488
Cumulative translation adjustment	5	–
	618,088	416,008
	1,520,624	1,030,231

ACCOMPANYING NC

On behalf of the Board:

Clifford A. Rae
DIRECTOR

Stephen J. Savidant

Consolidated Statements of Net Income and Retained Earnings

[illegible]ANDS OF DOLLARS, EXCEPT PER [illegible]

YEARS ENDED DECEMBER 31	2000	1999
[illegible]		
Petroleum and natural gas sales	909,315	400,505
Royalties	(200,488)	(73,832)
	708,827	326,673
[illegible]		
Production	56,198	48,340
General and administrative	24,266	17,353
Interest and other financing charges	65,012	6,732
Depletion, depreciation and amortization	192,839	147,511
Other	1,732	(231)
Minority interest	426	–
	340,473	219,705
Income before income taxes	368,354	106,968
Income taxes		
Current	17,195	7,703
Future	143,430	30,777
Net income	207,729	68,488
Retained earnings, beginning of year	68,488	–
Cash issued under incentive share option plan [NOTE 8]	(5,772)	–
Retained earnings, end of year	270,445	68,488
Net income per share [NOTE 8]		
Basic	3.49	1.15
Fully diluted	3.37	1.12

Consolidated Statements of Cash Flow

(THOUSANDS OF DOLLARS

YEARS ENDED DECEMBER 31	2000	1999
Operating Activities		
Net income	207,729	68,488
Add (deduct) items not involving cash		
Depletion, depreciation and amortization	192,195	146,499
Deferred revenue recognized in the year	49,334	(1,320)
Future income taxes	143,430	30,777
Minority interest	426	–
Funds from operations	593,114	244,444
Net change in non-cash working capital	(78,246)	20,665
Cash (used in) provided by operating activities	514,868	265,109
Investing Activities		
Exploration and development of oil and natural gas properties	(356,971)	(240,550)
Acquisition of equipment and other assets	(4,684)	(2,616)
Acquisition of oil and natural gas properties	(93,097)	(6,821)
Acquisition of Atalaya Energy S. A. [NC	(54,530)	–
Acquisition of Kintail Energy Inc.	–	(41,471)
Disposition of oil and natural gas properties	30,533	10,334
Increase in other assets	(14,956)	–
Net change in non-cash working capital	14,997	4,695
Cash (used in) provided by investing activities	(478,708)	(276,429)
Financing Activities		
Cash issued under incentive share option plan	(5,772)	–
Share capital issued [NOTE	118	–
Drawings on long-term debt [N	74,504	4,131
Foreign exchange	(21)	–
(Decrease) increase in deferred revenue and other liabilities	(104,989)	7,189
Cash (used in) provided by financing activities	(36,160)	11,320
Net change in cash	–	–
Cash, beginning of year	–	–
Cash, end of year	–	–
Funds from operations per share		
Basic	9.96	4.10
Fully diluted	9.56	3.97

SEE ACCOMPANYING NOT

Notes to Consolidated Financial Statements

DECEMBER 31, 2000 AND 1999

DOLLARS)

NOTE 1 :

Summary of Significant Accounting Policies

These financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada.

Consolidation

The consolidated financial statements of Canadian Hunter Exploration Ltd. (the "Corporation") include the financial position and the results of operations for all of its subsidiaries. A substantial portion of the Corporation's activities are conducted jointly with others and the consolidated financial statements reflect only the Corporation's proportionate interest in such activities.

Property, plant and equipment

The Corporation follows the full cost method of accounting for oil and natural gas operations, as prescribed by The Canadian Institute of Chartered Accountants, whereby all costs relating to the exploration for and the development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Capitalized costs include lease and reserve acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells and direct overhead expenditures related to exploration and development activities. Costs capitalized are depleted and depreciated using the unit-of-production method based on gross proven oil and natural gas reserves converted to a common unit of measure utilizing relative heating value. In determining its depletion base the Corporation includes the cost of unproven land and an estimate of future costs to be incurred in developing proven reserves. The entire proceeds from the disposal of oil and natural gas properties are applied as a reduction of capitalized costs, except when such disposition would result in a greater than 20 percent change in the rate of depletion, in which case a gain or loss on disposal would be recorded.

In applying the full cost method of accounting, the Corporation performs a ceiling test which restricts capitalized costs less accumulated depletion and depreciation, future income tax liabilities and site restoration from exceeding the estimated undiscounted value of future net revenue derived from gross proven oil and natural gas reserves, less the aggregate of estimated future general and administrative, financing, site restoration and abandonment costs, net of salvage values, and income tax costs, plus the lower of cost and estimated net realizable value of unproved properties. In calculating the ceiling test, year-end prices of oil and natural gas are used and all costs are assumed to be held constant.

Estimated future site restoration and abandonment costs are calculated using the unit-of-production method. Costs are based on engineering estimates using current costs and technology and in accordance with current legislation and industry practices. The annual charge is recorded as additional depletion and depreciation.

Depreciation of equipment and other assets is provided using the declining balance method at rates ranging from 10 percent to 33 percent per annum.

Inventories

Inventories of materials and supplies are carried at the lower of average cost and net realizable value.

Deferred revenue and other liabilities

Payments received for products not delivered until required in the future are deferred and recorded as revenue when the products are delivered or the right to take delivery expires. Payments received in respect of the natural gas transportation agreement are recorded as revenue over the term of the contract.

Foreign currency translation

All of the Corporation's foreign operations are self-sustaining. The accounts are translated using the current rate method in which assets and liabilities are converted to Canadian dollars at the exchange rate in effect at the balance sheet date and revenues and expenses are translated at the monthly average exchange rate during the month in which the transaction occurred. Translation gains or losses are included in a separate component of shareholders' equity.

Financial instruments

The Corporation periodically enters into financial instrument and commodity contracts to reduce its exposure to adverse changes in commodity prices, interest rates and foreign exchange rates. Costs and gains on hedge contracts are recognized in income in the same period as the hedged transactions are settled. Costs and gains associated with unwinding a hedged position, if material, would be recognized in the same period that the hedged item was recognized in income.

The fair value of accounts receivable, accounts payable and accrued liabilities, income taxes payable, and long-term debt approximates their carrying amounts.

Income taxes

The Corporation follows the liability method in accounting for income taxes. Under this method future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change occurs.

Pension costs

The Corporation has both a defined benefit and a defined contribution pension plan.

(a) Defined benefit plan

For the defined benefit pension plan, the Corporation uses the projected benefit actuarial method prorated on length of service and best estimate assumptions to value benefit obligations. The obligation for the defined benefit pension plan is determined through periodic actuarial reports that are based on projections of interest, employees' compensation levels, and length of service to the time of retirement. Adjustments arising from plan amendments, experienced gains and losses, and changes in assumptions are amortized over various periods depending on the nature of the adjustment, ranging from the term of the employment contract to which the adjustment relates, to the estimated average remaining service lives of the related employee group. For the purpose of calculating the expected return on plan assets, those assets are valued at fair value. Current service costs are expensed in the year.

Commencing January 1, 2000, the Corporation prospectively applied the new accounting recommendations for employee future benefits. In applying the new recommendation, the pension liability is calculated using a discount rate based on the current market interest rate of high quality debt instruments rather than an estimated rate. This resulted in a transitional asset of $5,754 which is being amortized over the estimated average remaining service life of 15 years.

(b) Defined contribution plan

Costs associated with the defined contribution pension plan are based upon specific amounts contributed on behalf of participating employees during the year and are expensed as incurred.

Share-based compensation plans

The Corporation has both an incentive share option plan and an employee share savings plan.

For the incentive share option plan no compensation expense is recognized when options are issued. If the options are repurchased from employees, the excess consideration paid over the exercise price of the option purchased is charged to retained earnings. If the option holder purchases the shares at the option price, the consideration received from the option holder is credited to share capital.

For the employee share savings plan, any contributions made by the Corporation are charged to compensation expense in the current year.

Use of estimates

Management is required to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period.

NOTE 2 :

[illegible]isitions

Effective March 1, 2000, the Corporation purchased 78 percent of the outstanding shares of Atalaya Energy S.A. ("Atalaya") for cash consideration of US$37,516 (CDN$54,530). Atalaya is engaged in the exploration for and production of natural gas and liquids in Argentina. The Corporation has made an offer to acquire the remaining 22 percent of the outstanding shares of Atalaya. This offer expires September 2001.

On December 22, 1999, the Corporation acquired all of the outstanding common shares of Kintail Energy Inc. ("Kintail") for cash consideration of $3.10 for each common share outstanding ($41,471).

These transactions were accounted for using the purchase method with the results of operations included in the consolidated statements of income from the dates of acquisition.

The Corporation allocated the purchase price to the assets and liabilities of the acquired companies as follows:

NET ASSETS ACQUIRED	2000 ATALAYA	1999 KINTAIL
Property, plant and equipment	**78,367**	79,604
Net non-cash working capital	**3,548**	(2,419)
Future income tax liability	**(14,242)**	(29,463)
Long-term debt	**–**	(6,251)
Minority interest	**(13,143)**	–
	54,530	41,471

NOTE 3 :

[illegible]

	2000	1999
Prepaid natural gas contract	**21,459**	27,180
Long-term sales tax receivable	**14,956**	–
	36,415	27,180
Less current portion	**3,351**	2,635
	33,064	24,545

Prepaid natural gas contract

The Corporation has a prepaid natural gas contract which represents a continuing obligation of a major independent producer to deliver to the Corporation approximately 10,865 mmbtu per day of natural gas. As at December 31, 2000 the remaining obligation totaled 25 bcf of natural gas (1999 – 29 bcf).

Long-term sales tax receivable

Long-term sales tax receivable consists of sales tax paid on the purchase of foreign properties. This tax is recoverable as revenue is earned from the properties purchased.

NOTE
4 : Property, Plant and Equipment

DECEMBER 31, 2000:

	COST	ACCUMULATED DEPLETION AND DEPRECIATION	NET BOOK VALUE
Oil and natural gas properties	**2,830,269**	**(1,591,124)**	**1,239,145**
Equipment and other assets	**48,703**	**(35,364)**	**13,339**
	2,878,972	**(1,626,488)**	**1,252,484**

DECEMBER 31, 1999:

	COST	ACCUMULATED DEPLETION AND DEPRECIATION	NET BOOK VALUE
Oil and natural gas properties	2,330,861	(1,407,373)	923,488
Equipment and other assets	44,034	(32,165)	11,869
	2,374,895	(1,439,538)	935,357

General and administrative expenses of $11,297 (1999 – $9,836) were capitalized.

NOTE
5 : Deferred Reven

	2000	1999
Prepaid natural gas contracts	**2,115**	61,538
Future site restoration	**37,107**	31,900
Natural gas transportation agreement	**13,022**	13,559
Provision for future lease costs	**3,613**	5,271
Pension liability [NOTE 9]	**665**	420
	56,522	112,688
Less current portion	**4,256**	8,475
	52,266	104,213

Prepaid natural gas contracts

In 1991 the Corporation entered into a natural gas pre-sale agreement with a co-generation facility in Syracuse, New York to supply 120 bcf of natural gas over a 16 year period, and in connection therewith a pre-payment equal to $101,328 was received. As at December 31, 1999, the Corporation's remaining supply commitment totaled 69 bcf of natural gas. On August 2, 2000 the remaining obligation was terminated for a payment of $103,082.

During the year the Corporation entered into an AECO/Nymex differential contract with a third party. As part of the contract, the Corporation received a payment for a call premium on 20,000 mmbtu per day to October 2001.

Future site restoration

The Corporation estimates total future site restoration and abandonment costs to be $78,792 at December 31, 2000 (1999 – $64,400) of which $37,107 (1999 – $31,900) has been accrued as a liability and $5,851 (1999 – $5,855) has been charged to income during the year.

Natural gas transportation agreement

The Corporation is a party to a natural gas transportation agreement for the utilization of pipeline capacity of 19,438 mmbtu per day to October 31, 2023. In return, a payment of US$10,500 was received which is being amortized into income over the term of the contract.

Provision for future lease costs

The provision for future lease costs relates to the subleasing of seven floors of space within the Calgary head office. This provision represents the difference between the original lease rate and the estimated amounts recoverable under subleases during the remaining term of the lease which expires in 2003. The provision is being amortized over the term of the lease.

NOTE
6 :

Long-Term Debt

	2000	1999
Canadian dollar debt	**144,271**	160,379
US dollar debt	**90,612**	–
	234,883	160,379

Bank credit facilities

The Corporation has arranged $500,000 of unsecured lines of credit with four major Canadian banks. Drawings on these lines have a revolving term which may, at the Corporation's discretion, be converted into an amortizing term. If the term date is not extended, the facilities will become repayable in equal quarterly payments over 4 years. No amount is required to be paid on these facilities within the next year and accordingly no current portion of long-term debt was recognized. The remaining available line of credit at December 31, 2000 is $198,808. The average rate of interest paid by the Corporation during the year on these facilities was 6.21 percent (1999 – 5.55 percent).

Interest and other financing charges

	2000	1999
Interest on long-term debt	**16,208**	6,732
Loss on termination of a prepaid natural gas contract	**48,634**	–
Other	**170**	–
	65,012	6,732

NOTE
7 :

[illegible]

The future income tax provision results primarily from the deduction, as permitted by tax legislation, of exploration and development expenditures in advance of the related deductions in the financial statements.

The effective tax rate used in the financial statements differs from the statutory income tax rate due to the following:

	2000	1999
Income before taxes	**368,354**	106,968
Statutory rate	**44.87%**	44.87%
Expected income taxes	**165,280**	47,997
Add/(deduct):		
Non-deductible crown charges, net of Alberta Royalty Tax Credit	**79,313**	30,234
Resource allowance	**(78,716)**	(35,859)
Tax benefit not previously recognized	**(529)**	(2,553)
Provincial royalty tax deduction	**(1,842)**	(306)
Large corporations tax	**2,194**	2,794
Other	**(5,075)**	(3,827)
Provision for income tax expense	**160,625**	38,480
Effective tax rate	**43.61%**	35.97%

NOTE

8 :

Share Capital

Authorized

Unlimited number of common shares

Unlimited number of preferred shares – issuable in series

Issued

Common shares

	2000		1999	
	SHARES (000S)	AMOUNT ($000S)	SHARES (000S)	AMOUNT ($000S)
Balance, beginning of year	**59,657**	**347,520**	59,564	347,520
Issued during year	**12**	**118**	93	–
Balance, end of year	**59,669**	**347,638**	59,657	347,520

Certain members of management have the right to receive 92,540 common shares which were issued at a price of $8.63 per share. These common shares were issued under the Corporation's share purchase plan and are held as security for loans receivable from management of $799. For financial statement reporting purposes, these loans have been deducted from shareholders' equity.

Common share options

The Corporation has an incentive share option plan under which options granted to acquire common shares vest proportionately over five years and expire ten years after the grant date. The exercise price is equal to the market price of the Corporation's common shares on the last trading day preceding the date of grant.

	2000		1999	
	NUMBER OF OPTIONS (000S)	WEIGHTED AVERAGE PRICE/SHARE	NUMBER OF OPTIONS (000S)	WEIGHTED AVERAGE PRICE/SHARE
Outstanding at beginning of year	**2,224**	**9.84**	–	–
Granted	**803**	**23.92**	2,282	9.85
Exercised	**(292)**	**9.67**	–	–
Forfeited	**(40)**	**14.46**	(58)	10.02
Outstanding at end of year	**2,695**	**13.99**	2,224	9.84
Exercisable at end of year	**153**	**10.14**	–	–

At December 31, 2000 the following options to purchase common shares were outstanding:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICE	NUMBER OF OPTIONS (000S)	WEIGHTED AVERAGE EXERCISE PRICE	WEIGHTED AVERAGE YEARS TO EXPIRY	NUMBER OF OPTIONS (000S)	WEIGHTED AVERAGE EXERCISE PRICE
Under $15.00	1,855	$9.60	8.0	145	$9.59
$15.00 to $25.00	39	$18.35	8.4	6	$18.94
Over $25.00	801	$23.94	9.2	2	$25.10
Total	2,695	$13.99	8.4	153	$10.14

At December 31, 2000, there were 2,863,286 (December 31, 1999 – 3,626,000) common shares reserved for the granting of additional options.

Earnings per share and funds from operations per share

Earnings per common share and funds from operations per common share have been calculated using the weighted average number of common shares for 2000 of 59,574,775 (1999 – 59,564,068). Fully diluted earnings per common share have been calculated based on the assumption that all options issued, to the extent they are not antidilutive, have been exercised. For 2000, the fully diluted earnings per share amount assumes 62,244,550 fully diluted shares outstanding (1999 – 61,880,363), and includes imputed interest of $1,725 (1999 – $1,064) at a rate of 5 percent (1999 – 5 percent) on the proceeds from the exercise of options.

NOTE 9 :

Pension Plan

For the current year, the Corporation used an independent actuary for determining the defined benefit pension plan funding and accounting reporting requirements.

Summary information relating to the defined benefit plan at December 31, 2000 is as follows:

Significant actuarial assumptions:	
Expected long-term rate of return on plan assets (%)	7.0
Discount rate (%)	7.0
Rate of compensation increase (%)	4.5
Accrued benefit obligation:	
Accrued benefit obligation, beginning of year	16,450
Current service cost	222
Interest cost	1,184
Actuarial losses	757
Benefits paid	(904)
Accrued benefit obligation, end of year	17,709
Plan assets*:	
Fair value of plan assets, beginning of year	21,783
Actual return on plan assets	1,918
Employer contributions	151
Benefits paid	(904)
Fair value of plan assets, end of year	22,948
Funded status – plan surplus:	5,239
Unamortized net actuarial gains	552
Unamortized net transitional asset	(5,370)
Net accrued benefit asset	421
Net balance sheet liability	665
Excess of fund assets over net balance sheet liability	1,086
Pension expense:	
Defined benefit	344
Defined contribution	1,017
	1,361

*Pension fund assets consist of short-term and money market investments.

NOTE

10: Financial Instruments

Financial contracts

To reduce its exposure to adverse changes in commodity prices, interest rates and foreign exchange rates, from time-to-time the Corporation utilizes financial instruments such as swaps and fixed commodity contracts to hedge against market fluctuations.

Commodity contracts

At December 31, 2000, the Corporation had the following natural gas hedging positions in place:

CONTRACT TYPE	CONTRACT PERIOD	NOTIONAL CONTRACT AMOUNT (UNITS)	AVERAGE FIXED PRICE ($/UNIT)	UNRECOGNIZED LOSS AT DEC. 31, 2000
AECO fixed price	January 2001 to October 2005	20,000 GJ/day	$4.15	61,727
AECO/NYMEX differential	January 2001 to October 2001	20,000 mmbtu/day	US$0.045	11,878

The AECO/NYMEX differential has a US$5.00/mmbtu Nymex ceiling. The AECO fixed price contract was entered into simultaneously with the termination of the prepaid natural gas contract.

The above estimated unrecognized amounts are based on the market value of these financial instruments as at year end, and represent the amounts the Corporation would receive or pay to terminate the contracts at year end. No amount for these instruments is recorded in the financial statements.

Credit risk

A significant portion of the Corporation's accounts receivable are due from entities in the oil and gas industry. Concentration of credit risk is mitigated by having a broad customer base, which includes a significant number of companies engaged in joint operations with the Corporation. The Corporation routinely assesses the financial strength of its partners and customers, including parties involved in marketing or other commodity arrangements.

The Corporation is exposed to credit risk associated with possible non-performance by financial instrument counter parties. The Corporation believes the risks of non-performance are minimal as the counter parties are major financial institutions that have an investment-grade credit rating as determined by recognized credit rating agencies. The Corporation also limits its total exposure to individual counter parties.

Off-Balance-Sheet risk

The Corporation entered into a foreign exchange forward contract to hedge its net investment in a self-sustaining foreign subsidiary. This forward contract to exchange US$38,983 for Canadian dollars at an exchange rate of 1.4529 matures on September 2005. As a result of the forward contract, the exchange gains and losses recorded on translation of the subsidiaries' financial statements will be offset by the gains and losses attributable to the foreign exchange forward contract.

NOTE

11: Commitments

Operating leases under existing lease commitments are as follows:

2001	4,869
2002	4,443
2003	1,076
	10,388

NOTE
12:

Statements of Cash Flow

The net changes in non-cash working capital consist of the following:

	2000	1999
Cash (used in) provided by		
Accounts receivable	**(148,444)**	(24,546)
Inventories	**(14,327)**	3,831
Accounts payable and accrued liabilities	**81,774**	42,785
Income taxes payable	**14,200**	5,709
	(66,797)	27,779
Atalaya Energy S.A. net working capital [note 2]	**3,548**	–
Kintail Energy Inc. net working capital [note 2]	**–**	(2,419)
	(63,249)	25,360

The change in non-cash working capital relates to the following activities:

	2000	1999
Operating	**(78,246)**	20,665
Investing	**14,997**	4,695
	(63,249)	25,360

Cash taxes paid in 2000 were $3,009 (1999 – $1,994), and cash interest paid in 2000 was $15,419 (1999 – $8,990).

NOTE
13:

Segmented Information

The Corporation has operations in Canada and Argentina. All activities relate to the exploration, development and production of oil, liquids and natural gas.

	CANADA		ARGENTINA		TOTAL CORPORATE	
	2000	1999	2000	1999	2000	1999
Petroleum and natural gas sales	**895,592**	400,505	**13,723**	–	**909,315**	400,505
Property, plant and equipment	**1,096,577**	935,297	**155,907**	60	**1,252,484**	935,357

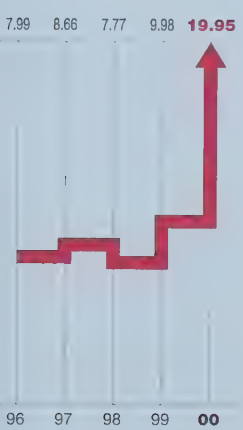
NOTE
14:

Reclassification of Comparative Data

Certain comparative amounts have been reclassified to conform with current year presentation.

Return on
Capital Employed
(%)

Cash Netback
($/boe)



Five Year Review

($ MILLIONS EXCEPT PER SHARE AMOUN

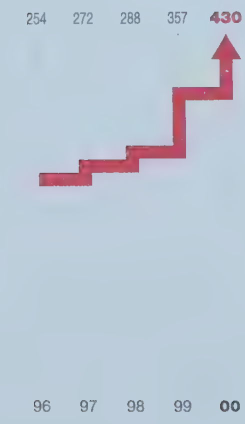
	2000	1999	1998	1997	1996
Financial					
Revenues					
Oil and natural gas sales	**909.3**	400.5	266.2	260.4	227.8
Royalties	**(200.5)**	(73.8)	(43.8)	(44.6)	(35.8)
	708.8	326.7	222.4	215.8	192.0
Expenses					
Production	**56.2**	48.4	34.8	28.8	23.8
General and administrative	**24.3**	17.3	11.0	9.4	11.4
Interest and other financing charges	**65.0**	6.7	8.8	8.8	8.8
Depletion, depreciation and amortization	**192.8**	147.5	120.8	115.0	114.7
Other	**1.7**	(0.2)	(0.4)	5.5	4.5
Minority interest	**0.5**	–	–	–	–
	340.5	219.7	175.0	167.5	163.2
Taxes					
Current	**17.2**	7.7	8.9	–	–
Future	**143.4**	30.8	11.8	19.3	11.5
	160.6	38.5	20.7	19.3	11.5
Net Income	**207.7**	68.5	26.7	29.0	17.3
Per common share (BASIC)	**3.49**	1.15	0.45	0.49	0.29
Per common share (FULLY DILUTED)	**3.37**	1.12	0.45	0.49	0.29
Funds from Operations	**593.1**	244.4	156.2	160.9	142.1
Per common share (BASIC)	**9.96**	4.10	2.62	2.71	2.39
Per common share (FULLY DILUTED)	**9.56**	3.97	2.62	2.71	2.39
Balance Sheet Information					
Long-term debt	**234.9**	160.4	150.0	125.0	125.0
Working capital surplus (deficiency)	**30.7**	(40.4)	(10.3)	4.0	3.8
Shareholders' equity	**618.0**	416.0	347.5	285.9	389.8
Common shares outstanding (THOUSANDS)	**59,577**	59,564	59,564	59,564	59,564
Fully diluted shares outstanding (THOUSANDS)	**62,245**	61,880	59,564	59,564	59,564
Key Financial Ratios					
Return on average shareholders' equity (%)	**40**	18	8	9	4
Return on capital employed (%)	**35**	12	6	7	5
Net debt to trailing cash flow ratio	**0.4**	0.7	1.0	0.8	0.9
Debt to total capitalization (%)	**28**	28	30	30	24

NOTE INCOME STATEMENT AND STA EMEN

Five Year Review

Operating Expense
($/boe)

Natural Gas Production
(mmcf/d)



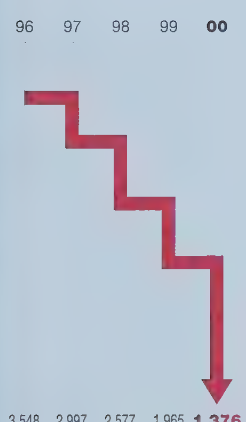
	2000	1999	1998	1997	1996
Operating					
Production					
Natural gas (mmcf/d)	**430**	357	288	272	254
Natural gas liquids (bbls/d)	**8,068**	6,216	5,439	5,047	4,639
Crude oil (bbls/d)	**1,376**	1,965	2,577	2,997	3,548
Total (boe/d)	**81,104**	67,721	56,022	53,457	50,613
Developed Land Holdings (THOUSAND ACRES)					
Gross	**976**	725	578	770	767
Net	**622**	499	400	565	538
Undeveloped Land Holdings					
Gross	**2,766**	2,011	1,791	1,219	1,323
Net	**1,879**	1,453	1,313	926	931
Capital Expenditures ($ MILLION)					
Lease acquisition and rentals	**75.0**	22.8	29.0	34.6	19.0
Seismic	**12.2**	13.1	4.6	8.2	4.5
Drilling and completions	**171.6**	128.8	105.0	82.8	40.4
Facilities	**86.9**	66.0	46.2	30.9	24.0
Capitalized general and administrative	**11.3**	9.8	11.0	9.8	9.2
Exploration and development expenditures	**357.0**	240.5	195.8	166.3	97.1
Acquisitions	**147.6**	48.3	14.6	5.6	56.3
Dispositions	**(30.5)**	(10.3)	(3.1)	(146.0)	(55.8)
Other	**4.7**	2.6	5.7	2.5	1.7
Net capital expenditures	**478.8**	281.1	213.0	28.4	99.3
Reinvestment Ratio					
Exploration and development capital only					
Canada	**60**	98	125	103	68
Argentina	**98**	–	–	–	–
Corporate	**60**	98	125	103	68
Total capital expenditures					
Canada	**59**	115	136	18	70
Argentina	**1,836**	–	–	–	–
Corporate	**81**	115	136	18	70
Recycle Ratio					
(NET ACQUISITION COST)	**2.9**	2.0	1.4	4.4	2.2
Employees					
Calgary office	**215**	182	167	151	144
Argentina	**5**	1	–	–	–
Field	**12**	11	12	9	10

Reserves Reconcilia

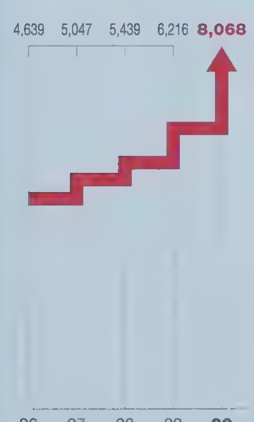
	NATURAL GAS (bcf) PROVEN	NATURAL GAS (bcf) RISKED PROBABLE	NATURAL GAS (bcf) ESTABLISHED	CRUDE OIL AND NGLS (mmbbls)* PROVEN	CRUDE OIL AND NGLS (mmbbls)* RISKED PROBABLE	CRUDE OIL AND NGLS (mmbbls)* ESTABLISHED
January 1, 1996	621	76	697	18.8	2.8	21.6
Discoveries and extensions	108	–	108	1.3	–	1.3
Revisions of prior estimates	(3)	(3)	(6)	1.4	0.4	1.8
Purchases	70	18	88	1.2	0.2	1.4
Dispositions	(27)	–	(27)	(1.4)	(0.5)	(1.9)
Production	(93)	–	(93)	(3.0)	–	(3.0)
January 1, 1997	676	91	767	18.3	2.9	21.2
Discoveries and extensions	170	11	181	1.8	0.2	2.0
Revisions of prior estimates	23	(4)	19	0.5	(0.4)	0.1
Purchases	4	–	4	0.1	–	0.1
Dispositions	(115)	(8)	(123)	(2.8)	(0.6)	(3.4)
Production	(100)	–	(100)	(2.9)	–	(2.9)
January 1, 1998	658	90	748	15.0	2.1	17.1
Discoveries and extensions	164	5	169	2.9	0.3	3.2
Revisions of prior estimates	9	(8)	1	4.1	0.6	4.7
Purchases	8	–	8	0.1	–	0.1
Dispositions	(2)	–	(2)	–	–	–
Production	(105)	–	(105)	(2.9)	–	(2.9)
January 1, 1999	732	87	819	19.2	3.0	22.2
Discoveries and extensions	239	8	247	3.0	0.1	3.1
Revisions of prior estimates	48	(12)	36	0.4	(0.8)	(0.4)
Purchases	29	1	30	0.7	–	0.7
Dispositions	(3)	–	(3)	–	–	–
Production	(130)	–	(130)	(3.0)	–	(3.0)
January 1, 2000	915	84	999	20.3	2.3	22.6
Discoveries and extensions	228	18	246	4.0	0.2	4.2
Revisions of prior estimates	(16)	(10)	(26)	0.3	(0.2)	0.1
Purchases	177	40	217	1.1	0.2	1.3
Dispositions	(10)	–	(10)	(0.1)	–	(0.1)
Production	(157)	–	(157)	(3.4)	–	(3.4)
January 1, 2001	**1,137**	**132**	**1,269**	**22.2**	**2.5**	**24.7**

NOTE: RESERVES IN 1996 150
RATE OF FIVE THOUSAND ON
CANADIAN HU
WERE OBTAINED FROM THE SPRO

Crude Oil Production
(bbls/d)



Natural Gas Liquids Production
(bbls/d)

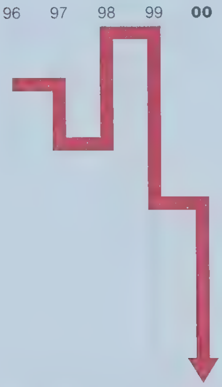


Segmented Information

FOR THE YEAR ENDED DECEMBER 31 (UNAUDITED)	CANADA 2000	CANADA 1999	ARGENTINA 2000	ARGENTINA 1999
Financial				
Gross production revenue	**895.6**	400.5	**13.7**	–
Funds from operations	**585.8**	244.4	**7.3**	–
Net income	**206.9**	68.5	**0.8**	–
Capital expenditures				
Exploration and development	**349.9**	240.5	**7.1**	–
Acquisitions	**21.0**	48.3	**126.6**	–
Dispositions	**(30.5)**	(10.3)	**–**	–
Operating				
Production				
Natural gas	**416**	357	**14**	–
Crude oil	**1,376**	1,965	**–**	–
Liquids	**7,992**	6,216	**76**	–
Total	**78,769**	67,721	**2,335**	–
Prices				
Natural gas	**5.06**	2.60	**2.13**	–
Crude oil	**34.64**	26.01	**–**	–
Liquids	**36.39**	18.90	**42.84**	–
Netback				
Product revenue	**31.07**	16.20	**13.74**	–
Royalties	**(6.90)**	(2.98)	**(1.63)**	–
Operating expense	**(1.85)**	(1.96)	**(2.86)**	–
Operating netback	**22.32**	11.26	**9.25**	–
Reserves				
Natural gas				
Developed producing	**799.4**	724.3	**60.8**	–
Developed non-producing	**9.0**	16.0	**–**	–
Undeveloped	**161.0**	174.6	**107.0**	–
Total proven	**969.4**	914.9	**167.8**	–
Risked probable	**92.2**	84.3	**40.1**	–
Crude oil and natural gas liquids				
Developed producing	**17.4**	16.8	**0.4**	–
Developed non-producing	**0.2**	0.2	**–**	–
Undeveloped	**3.6**	3.3	**0.6**	–
Total proven	**21.2**	20.3	**1.0**	–
Risked probable	**2.3**	2.4	**0.2**	–

Net Debt to Trailing Cash Flow

96 97 98 99 **00**

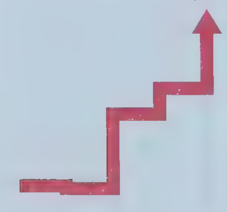


0.9 0.8 1.0 0.7 **0.4**

Net Undeveloped Land Holdings

(THOUSAND ACRES)

931 926 1,313 1,453 **1,879**



96 97 98 99 **00**

Drilling History

	2000		1999		1998		1997		1996	
	GROSS	**NET**	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Exploratory										
Natural gas	**198**	**172.4**	152	116.9	68	50.8	38	29.3	14	11.8
Crude oil	**–**	**–**	2	1.5	1	0.4	4	3.4	2	2.0
Dry	**41**	**34.2**	34	29.1	19	12.7	26	20.7	21	12.1
Total exploratory	**239**	**206.6**	188	147.5	88	63.9	68	53.4	37	25.9
Development										
Natural gas	**85**	**58.6**	64	36.2	64	40.5	60	36.0	40	26.8
Crude oil	**–**	**–**	2	1.1	5	2.7	6	4.5	–	–
Dry	**8**	**5.8**	12	10.8	12	5.4	5	3.9	7	4.4
Total development	**93**	**64.4**	78	48.1	81	48.6	71	44.4	47	31.2
Total wells drilled	**332**	**271.0**	266	195.6	169	112.5	139	97.8	84	57.1
Success ratio										
Exploratory	**83**	**83**	82	80	78	80	62	61	43	53
Development	**91**	**91**	85	78	85	89	93	91	85	86
Overall	**85**	**85**	83	80	82	84	78	75	67	71

Oil and Natural Gas Wells

	PRODUCING WELLS		NON-PRODUCING WELLS		TOTAL WELLS	
	GROSS	NET	GROSS	NET	GROSS	NET
Natural gas wells						
Alberta	794	577	463	323	1,257	900
British Columbia	364	244	105	71	469	315
Argentina	30	7	4	1	34	8
Total	1,188	828	572	395	1,760	1,223
Oil wells						
Alberta	61	21	21	9	82	30
British Columbia	17	17	8	7	25	24
Argentina	–	–	–	–	–	–
Total	78	38	29	16	107	54
Total wells	1,266	866	601	411	1,867	1,277

Major Producing Properties

	2000 PRODUCTION (boe/d)	PERCENT NATURAL GAS	PERCENT OF TOTAL
Deep Basin	47,121	86	58
Border/Corridor	11,902	91	15
Kaybob	7,402	93	9
Claresholm/Parkland	5,898	96	7
Lethbridge	3,900	100	5
Argentina	2,335	97	3
Other	2,546	51	3
Total	81,104	88	100

Quarterly Financial Information (Unaudited)

($ MILLIONS EXCEPT PER SHARE DATA)	THREE MONTHS ENDED MAR 31	JUN 30	SEP 30	DEC 31	TOTAL
Fiscal 2000					
Revenue before royalties	130.6	174.2	227.6	376.9	909.3
Net Income	24.8	36.2	33.5	113.2	207.7
Per common share (BASIC)	0.42	0.60	0.56	1.91	3.49
Per common share (FULLY DILUTED)	0.40	0.59	0.55	1.83	3.37
Funds from operations	86.7	112.5	149.3	244.6	593.1
Per common share (BASIC)	1.45	1.89	2.51	4.11	9.96
Per common share (FULLY DILUTED)	1.40	1.80	2.40	3.96	9.56
Capital expenditures					
Exploration and development	120.2	56.7	64.1	116.0	357.0
Acquisitions	54.3	6.5	14.5	72.3	147.6
Dispositions	(0.2)	(0.2)	(28.0)	(2.1)	(30.5)
Production					
Natural gas (mmcf/d)	384	412	434	490	430
Crude oil (bbls/d)	1,703	1,466	1,266	1,074	1,376
Liquids (bbls/d)	7,748	6,954	7,923	9,631	8,068
Total (boe/d)	73,392	77,166	81,442	92,289	81,104
Prices					
Natural gas ($/mcf)	2.91	3.94	4.89	7.43	4.96
Crude oil ($/bbl)	38.47	36.57	33.76	27.06	34.64
Liquids ($/bbl)	32.12	32.28	37.51	42.02	36.46
Fiscal 1999					
Revenue before royalties	77.2	88.7	107.7	126.9	400.5
Net Income	10.0	9.7	18.9	29.9	68.5
Per common share (BASIC)	0.17	0.16	0.32	0.50	1.15
Per common share (FULLY DILUTED)	0.16	0.16	0.31	0.49	1.12
Funds from operations	46.3	50.1	67.9	80.1	244.4
Per common share (BASIC)	0.78	0.84	1.14	1.34	4.10
Per common share (FULLY DILUTED)	0.75	0.81	1.10	1.31	3.97
Capital expenditures					
Exploration and development	86.3	30.1	49.1	75.0	240.5
Acquisitions	0.7	3.6	0.3	43.7	48.3
Dispositions	(10.3)	–	–	–	(10.3)
Production					
Natural gas (mmcf/d)	350	348	354	376	357
Crude oil [illegible]	1,999	2,120	1,897	1,848	1,965
Liquids [illegible]	6,269	5,260	6,621	6,703	6,216
Total [illegible]	66,689	65,444	67,537	71,166	67,721
Prices					
Natural gas [illegible]	2.14	2.42	2.75	3.04	2.60
Crude oil [illegible]	19.56	23.33	28.31	33.52	26.01
Liquids [illegible]	11.14	15.62	21.48	26.01	18.90

Conversion Rate Comparison

	10:1 CONVERSION 2000	1999	1998	1997	6:1 CONVERSION 2000	1999	1998	1997
Production								
Average daily (boe/d)	**52,440**	43,905	36,820	35,292	**81,104**	67,721	56,022	53,457
Annual (mmboe)	**19.2**	16.0	13.4	12.9	**29.7**	24.7	20.4	19.5
Natural gas (%)	**82**	81	78	77	**88**	88	86	85
Netback ($/boe)								
Revenue	**47.16**	24.99	19.80	20.22	**30.49**	16.20	13.02	13.35
Royalties	**(10.40)**	(4.61)	(3.27)	(3.47)	**(6.72)**	(2.98)	(2.15)	(2.29)
Operating costs	**(2.91)**	(3.02)	(2.59)	(2.23)	**(1.88)**	(1.96)	(1.70)	(1.47)
Operating netback	**33.85**	17.36	13.94	14.52	**21.89**	11.26	9.17	9.59
General and administrative expense	**(1.26)**	(1.08)	(0.82)	(0.73)	**(0.81)**	(0.70)	(0.54)	(0.48)
Interest expense	**(0.84)**	(0.42)	(0.65)	(0.68)	**(0.55)**	(0.27)	(0.43)	(0.45)
Current taxes	**(0.90)**	(0.48)	(0.66)	–	**(0.58)**	(0.31)	(0.43)	–
Cash netback	**30.85**	15.38	11.81	13.11	**19.95**	9.98	7.77	8.66
Consolidated Reserves (mmboe)								
Proven	**135.9**	111.8	92.4	80.8	**211.8**	172.8	141.2	124.6
Risked probable	**15.7**	10.7	11.7	11.1	**24.6**	16.3	17.5	17.1
Established	**151.6**	122.5	104.1	91.9	**236.4**	189.1	158.7	141.7
Proven Reserve Life Index (YEARS)	**7.1**	7.0	6.9	6.3	**7.1**	7.0	6.9	6.3
Proven Reserves Added (mmboe)								
Discoveries and extensions	**26.8**	26.9	19.3	18.8	**42.0**	42.8	30.3	30.1
Engineering revisions	**(1.3)**	5.2	5.0	2.8	**(2.3)**	8.4	5.6	4.3
Acquisitions (dispositions)	**17.8**	3.3	0.7	(13.8)	**29.0**	5.1	1.1	(21.2)
Performance Ratios on Proven Reserves								
Finding and development cost ($/boe)								
Canada	**13.71**	7.49	8.06	7.70	**8.82**	4.70	5.45	4.83
Argentina	**–**	–	–	–	**–**	–	–	–
Corporate	**13.99**	7.49	8.06	7.70	**9.00**	4.70	5.45	4.83
All-in replacement cost ($/boe)								
Canada	**13.63**	7.87	8.29	3.32	**8.78**	4.95	5.60	1.96
Argentina	**7.30**	–	–	–	**4.48**	–	–	–
Corporate	**10.95**	7.87	8.29	3.32	**6.91**	4.95	5.60	1.96
Production replacement (%)								
(excluding net acquisitions)								
Canada	**137**	201	181	167	**138**	207	176	176
Argentina	**–**	–	–	–	**–**	–	–	–
Corporate	**133**	201	181	167	**134**	207	176	176
(including net acquisitions)								
Canada	**134**	221	186	60	**134**	228	181	67
Argentina	**3,495**	–	–	–	**3,490**	–	–	–
Corporate	**226**	221	186	60	**231**	228	181	67

Corporate Information

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Brascan Corporation
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The Honourable E. Peter Lougheed
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Corporate Director,
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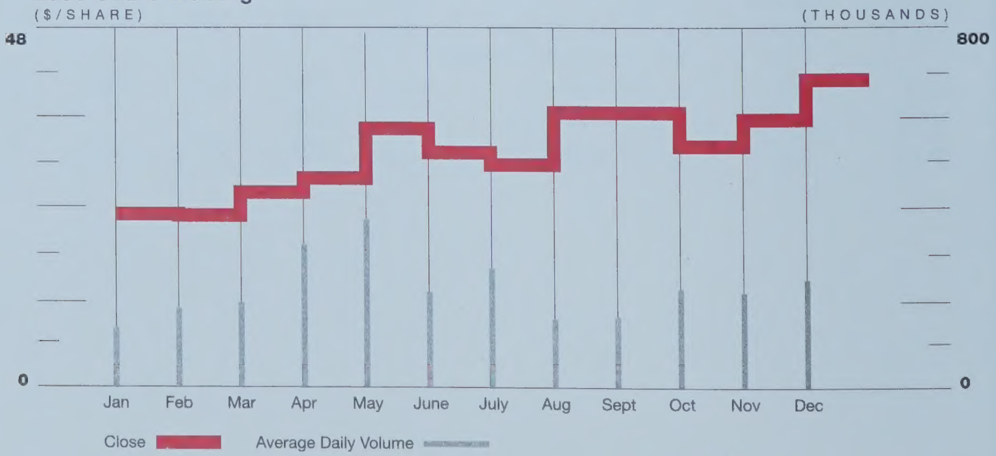

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